SOx RECLAIM STUDY

FINAL REPORT

MODULE 3A: WET/DRY SCRUBBING TECHNOLOGY FOR REFINERY FLUID CATALYTIC CRACKING UNITS (FCCUs), REFINERY BOILERS/HEATERS, AND REFINERY SULFUR RECOVERY UNITS (SRUs) AND TAIL GAS TREATMENT PROCESSES

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I. EXECUTIVE SUMMARY

ETS/AEC were commissioned to conduct an engineering evaluation and cost analysis assessment for technologies to control SOx emissions from refineries in the South Coast Air Quality Management District (SCAQMD). The physical scope of this study encompassed six petroleum refining companies in the South Coast area (listed alphabetically):

- BP (Carson)
- Chevron (El Segúndo)
- ConocoPhillips (dual locations in Carson and Wilmington)
- ExxonMobil (Torrance)
- Tesoro (Wilmington)
- Valero (Wilmington)

The goal of the overall project was to conduct an evaluation of emission control technologies for further reducing SOx emissions. The particular focus of Module 3A in this study was to determine how scrubbing technologies could reduce the SOx emissions from the refinery FCCUs (Fluid Catalytic Cracking Units); boilers, heaters, and similar fired equipment; and the SRU/TGTUs (Sulfur Recovery Units and Tail Gas Treating Units). This module, therefore, deals with what are considered "post-combustion" treatment techniques—that is, treating flue or stack gas streams prior to being discharged to the atmosphere.

Outputs of the program include: 1) an evaluation of existing commercially available control technologies, starting with the most effective control technology, 2) recommendations to SCAQMD on various technologies that could potentially be used to achieve additional emission reductions, 3) various concentration targets that could be achieved with each technology, 4) the estimated emission reductions, 5) the multimedia impacts, 6) energy impacts of the technologies, and the 7) cost effectiveness associated with the control technology.

As part of this project, in the three-week period beginning on the 22nd of September 2008, AEC engineers visited the six above-mentioned refineries, seeing two of them per week. The purpose of the visits was to assess the performance of the facilities' existing SOx emission control equipment and the available space to install supplemental treatment equipment. An additional objective of the visits was to obtain emission and operational information pertinent to the successful fulfillment of the overall program objectives.

As follow-up for the purpose of resolving any outstanding issues, a second visit was made to all but one of the refineries during the week of February 16, 2009. The following refiners were re-visited; BP (2/17), Tesoro and Valero (2/18), Chevron and ConocoPhillips-Wilmington (2/19). These visits were conducted by Robert Kunz (ETS) and Tav Heistand (AEC), with Minh Pham and Joe Cassmassi (2/17/ and 2/19) of SCAQMD in attendance.

In the final project tally, more than 150 individual measures were evaluated for cost and effectiveness. Of that total, approximately 120 were included in this Module 3A study.

Scrubbing methods to remove SOx from exhaust gas streams can be categorized as one of two types: wet or dry. Wet scrubbing systems are either of the regenerative or non-regenerative variety. Each of the three mentioned scrubber types (i.e., dry plus regenerative and non-regenerative wet) has been demonstrated to be technically feasible in a host of projects in the petroleum, power, and other industries. They are not all equally effective in terms of SOx reductions, thus their commercial competitiveness is highly dependent on the individual applications. The ones on which the evaluation team concentrated are the following, which represent about the best performance levels expected for typical refinery applications. (For more information about the various scrubbing applications, see the AQMD Preliminary Draft Staff Report of April 2008):

Technology	Performance
Non-regenerative wet gas scrubbing:	Up to 98% or 99% SOx reduction (in some cases, the lowest guaranteed outlet SOx concentration is on the order of 5 ppmv, which would supersede the 98%+ reduction figure)
Regenerative wet gas scrubbing:	Up to 95% SOx reduction (in some cases, the lowest anticipated outlet SOx concentration is on the order of 10 ppmv, which would supersede the 98%+ reduction figure)
Dry scrubbing:	Up to 85% or 90% SOx reduction (in some cases, the lowest anticipated outlet SOx concentration is on the order of 10 ppmv, which would supersede the stated reduction figure range)

Because of the very different stream characteristics amongst the three equipment types listed below, the technology choices investigated were very specific to the applications. Recognizing, for example, that dry scrubbers would ordinarily require a fairly hot gas inlet temperature, they were not considered for any SRU/TGTU installations. Regenerative wet gas scrubbers were quite competitive in those same SRU/TGTU installations. On the other hand, non-regenerative wet gas scrubbers were candidates for all three of the equipment types.

Equipment Type	Scrubbing Technologies Studied in Detail
FCCUs	Dry and Non-Regenerative Wet
SRU/TGTUs	Regenerative and Non-Regenerative Wet
Heaters/boilers/furnaces	Dry and Non-Regenerative Wet

The determination of Best Available Retrofit Control Technology (BARCT) recommendations was a two-part exercise: First, the potential SOx emissions reduction was estimated for each particular measure predicated on actual data from the 2005 baseline year, whenever it was available. Next, an attempt was made to calculate the measure's cost effectiveness (i.e., $ per ton of SOx reduced). Since each candidate technology was already known to be technically viable, it remained merely to choose the measure that gave both a large—if not the very largest—SOx reduction and a "reasonable" (hopefully relatively low) cost effectiveness ratio without incurring any insurmountable multi-media impacts.

The following table gives a summary of the Module 3A cost effectiveness ratios by refinery following implementation of the respective measures selected by ETS/AEC:

Table EX-1

Module 3A Cost Effectiveness ($/ton of SOx) by Refinery

Refinery:	1	2	3	4	5	6	**Avg. for All**
Equipment Type							
FCCU	$14.4k	$76.2k	$36.6k	$42.1k	$11.6k	$12.8k	**$24.6k**
SRU/TGTU	N/A	$39.0k	N/A	N/A	$123.2k	$36.4k	**$46.8k**
Htrs/Blrs/etc.	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
All Above Types:	$14.4k	$58.8k	$36.6k	$42.1k	$123.2k	$18.4k	**$28.8k**

Note: The entry "N/A" above means one of the following three things for the relevant refinery and equipment type combination: (a) for technical reasons, a Module 3A measure was not practical or (b) the cost effectiveness of candidate measures were too high for selection; or (c) a Module 2 measure (see the separate report) was determined to be the best technology for the equipment type at that site.

For this specific study, the study team estimates that any given cost effectiveness number has an *expected range* someplace within the band of -10% to +50%.
In arriving at the BARCT recommendations, the ETS/AEC engineers looked first and foremost for proven technologies and established manufacturers who could demonstrate the viability of their packages in the same or similar applications. Next, the list of candidate measures was further reduced to exclude any specific applications that would not work for a given piece of equipment because of flow-rate; gas properties; space needs; infrastructure requirements; or other reasons. After that, as was indicated previously, the team did the necessary calculations to arrive at estimated SOx reductions and cost effectiveness ratios. The final step was the selection of individual measures from each refinery that would give aggressive total SOx reductions without incurring extremely high annualized operating costs (i.e., those measures with low or acceptably moderate cost effectiveness parameters).

The final estimates of SOx reductions for the Module 3A BARCT-designated measures are tabulated below:

Table EX-2

Module 3A Forecasted SOx Reductions (tons/day) by Refinery

Refinery:	1	2	3	4	5	6	**Total**
Equipment Type							
FCCU	0.58	0.19	0.28	0.20	0.87	0.94	**3.07**
SRU/TGTU	N/A	0.17	N/A	N/A	0.06	0.29	**0.52**
Htrs/Blrs/etc.	N/A	N/A	N/A	N/A	N/A	N/A	**0.00**
All Above Types:	0.58	0.36	0.28	0.20	0.93	1.23	**3.58**

Note: The entry "N/A" above means one of the following three things for the relevant refinery and equipment type combination: (a) for technical reasons, a Module 3A measure was not practical or (b) the cost effectiveness of candidate measures were too high for selection; or (c) a Module 2 measure (see the separate report) was determined to be the best technology for the equipment type at that site.

The anticipated utility and energy impacts on the refineries following implementation of the Module 3A BARCT measures are widely different from one another. This is a topic that can only be addressed in details within the facility (confidential) reports. For general guidance, the following table can be consulted:

Table EX-3

Approximate Range of Impact by Measure Type

Utility/Service	Unit of Measure	NWGS	RWGS	Dry Scrubbing
Natural Gas	MM BTU/year	0	40k - 100k	0
Electricity	kw-hour/year	700k - 33MM	1 – 2.5MM	550k - 24MM
Water	MM gal/year	1 – 90	8 – 20	1 – 65
Wastewater	MM gal/year	1 – 40	8 – 20	0
Cooling water	MM BTU/year	20 – 1100k	80k – 200k	20 – 800
Compressed Air	1000 scf/year	20 – 1500	0	25k – 1.5MM
Solid Waste	tons/year	0 – 700	0	10 – 1200
Chemicals	tons/year	4 – 800	0	3 – 700

Legend: NWGS = *non-regenerative* and RWGS = *regenerative* wet gas scrubber

As recommended by ETS/AEC and based on the cases examined in this study, the capability of the scrubbing technologies to control SOx emissions from the refinery FCCUs, SRU/TGTUs, and boilers, heaters, furnaces, and other fired equipment ranges between zero and 1.0 tons/day (per refinery). All of the scrubbing technologies have the potential to offer very good SOx removal capabilities, from 80% - 98%+. However, actual emissions in the majority of scrubbing measures studied were low enough in the baseline year of 2005 such that the aforementioned percentage reductions are not anticipated. Instead, applications of scrubbing technologies in the SCAQMD areas are predicted to shrink emission levels to verifiable minimum SOx concentrations. As a result, removal percentages are expected to be limited by that minimum SOx concentration. Thus, the targeted removal efficiency due to installation of gas scrubbing in the SCAQMD area refineries varies from a high of approximately 90% down to nearly zero. Wet scrubbing offers the greatest potential to reduce SOx emissions—on a pure quantity basis—relative to the dry scrubbing options that were investigated.

After reviewing the conditions for the refinery applications of this module, one supplier of a non-regenerative wet scrubbing system, stated that they would expect to achieve an outlet emission of about 1 ppmv and would guarantee a level of 5 ppmv. The increase from expected to guaranteed levels is due to the uncertainty of test methods and accuracy of the test measurements employed during performance/compliance testing as well as the permissible tolerances in Continuous Emission Monitoring Systems (CEMS). After careful consideration of the various scrubbing approaches and review of the technical responses and guarantee statements offered by the suppliers of these technologies, it is the recommendation of the ETS team that non-regenerative wet scrubbing be considered on a purely technical basis as BARCT for the FCCUs, Refinery Boiler/Heaters, and SRU/TGTU processes under study in Module 3A, with an overall BARCT level of 5 ppmv.

The following is an overall summary of the high and low values of SOx emission reductions for the FCCUs evaluated in Module 3A. Table EX 4.1 provides the 2005 SOx baseline range of emissions across the refineries and Table EX 4.2 shows the range of projected SOx reductions based on the BARCT designations.

Table EX 4.1

SOx in Effluents from FCCU's (ppmv and lb/M bbl of FCCU Feed) -- The "Before" Case

Range	Equipment	FCCURate M bbl/day (FCCU Feed)[1]	FG Flow SCFM dry	SOx Load TPD (2005)[2]	SOx in FG ppmv (estimated)[3]	SOx in FG ppmv (refinery data)[4]	SOx in FG lb/M bbl (FCCU Feed)	RECLAIM Emission Factor lbs/M bbl (Developed 1993)[5]
Low	FCC	30	94,000	0.25	16	13	**7**	**13.7**
High	FCC	95	166,000	1.03	56	98	**35**	**13.7**
TOTAL EMISSIONS FOR 6 REFINERIES				**3.52**				

Note[1]: Reported FCCU Feed Rates by Refineries in SCAQMD Survey Questionnaire
Note[2]: All SOx Load TPD values are from 2005
Note[3]: All SOx in Flue Gas (ppmv) are estimated using the Flue Gas Flow and the SOx Load (TPD)
Note[4]: SOx in Flue Gas for 2005 developed using the following equation: ppmv (2005) = ppmv (refinery reference year) x (tpd emitted 2005 / tpd emitted for refinery reference year)
Note[5]: Allocation files for each facility developed based on reported data in 1993 as provided in SCAQMD Preliminary Draft Staff Report

Table EX 4.2

SOx in Effluents from FCCU's (ppmv and lb/M bbl of FCCU Feed) -- The "After" Case

Range	FCCU Rate M bbl/day (FCCU Feed)[1]	FG Flow SCFM dry	SOx Emissions Reduction TPD (98% reduction)[2]	SOx Load after treatment TPD	SOx in FG ppmv (est.)	RECLAIM Emission Factor lbs/M bbl (FCCU Feed)	SOx in FG ppmv (5 ppmv)[3]	SOx Emissions Reduction TPD	SOx Load after treatment TPD	% Efficiency (5 ppmv)[3]	RECLAIM Emission Factor lbs/M bbl (FCCU Feed)
Low	30	94,000	0.24	0.00	0.2	**0.1**	5	0.19	0.03	62%	**1.1**
High	95	166,000	1.01	0.02	1.1	**0.7**	5	0.93	0.12	95%	**3.4**
TOTAL REDUCTION FOR 6 REFINERIES			**3.45**					**3.07**	**0.46**		

Note[1]: Reported FCCU Feed Rates by Refineries in SCAQMD Survey Questionnaire
Note[2]: All control efficiencies are based on 98% maximum achievable control efficiency of Measure M1 selected as BARCT
Note[3]: SOx load after treatment and efficiencies based on a BARCT level of 5 ppmv

FINAL RECOMMENDATION BY ETS FOR BOTH MODULE 2 & MODULE 3A

Table EX-5 and EX-6 give a final recommendation of the total SOx emission reductions and average cost effectiveness ratios by refinery following implementation of the respective measures selected by ETS/AEC in both Modules 2 and 3A.

Table EX-5

Forecasted SOx Reductions (tons/day) by Refinery

Refinery:	1	2	3	4	5	6	**Total**
Equipment Type							
FCCU	0.58	0.19	0.28	0.20	0.87	0.94	3.07
SRU/TGTU	0.13	0.17	0.15	0.04	0.06	0.29	0.83
Fuel Gas	0.06	0.07	0.04	0.35	0.33	0.04	0.89
Htrs/Blrs/etc.	N/A	N/A	N/A	N/A	N/A	N/A	0.00
All Above Types:	0.77	0.43	0.47	0.59	1.26	1.27	4.78

Table EX-6

Cost Effectiveness ($/ton of SOx) by Refinery

Refinery:	1	2	3	4	5	6	**Avg. for All**
Equipment Type							
FCCU	$14,437	$76,211	$36,636	$42,103	$11,600	$12,849	**$24,572**
SRU/TGTU	$22,410	$39,000	$12,881	$54,686	$123,186	$36,359	**$37,412**
Fuel Gas	$2,395	$30,948	$46,905	$4,903	$21,071	$57,428	**$16,824**
Htrs/Blrs/etc.	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
All Above Types:	$14,770	$54,303	$29,982	$20,975	$36,025	$19,643	**$25,533**

Appendix A, Table A-1 has a summary of 2005 baseline emissions, estimated emission reductions, and the theoretical remaining emissions for each refinery. Appendix A, Table A-2, has a summary of the measures in Module 2 and Module 3A selected by ETS/AEC for this project applicable for each refinery, and the estimated cost effectiveness ratios for each refinery.

ETS believes that it is conceivable that an emission reduction of 4.78 tons per day can be achieved from the refineries implementing the commercially available measures described in this project within a construction time frame of approximately 3 calendar years or less following the completion of study designs and engineering.

One refinery has already installed a wet gas scrubber on its FCCU regenerator. As such, the opportunities to reduce SOx emissions at its FCCU are virtually nil for this refiner.

However, the estimated SOx reductions (derived from the 2005 baseline number and an outlet concentration of 5 ppmv) and cost effectiveness ratio (estimated from refinery and overall study data) were included for comparison. It should be noted that the cost effectiveness ratio for this refinery was not included in any of the average cost effectiveness calculations.

For the heaters and boilers, post-combustion emission control is often expensive due to the combination of the relatively low concentrations of SOx in flue gases and the division of the fuel gas stream among a number of heaters and boilers. Pre-combustion control, studied in Module 2, has been found to be more suitable for the majority of situations.

While the measures in Module 3A are assumed to be largely independent of one another, it is reasonable to anticipate significant dependence of Module 3 measures on measures from other Modules in this study. The above data are believed to be representative for the 2005 baseline year. Results may be different when examining more current data.

The reader will note that the cost effectiveness ratios estimated in this study are higher, even substantially so in many cases, than the cost effectiveness ratios estimated in studies of very similar control technologies in other refineries. There are many reasons for this result. First, costs for labor, materials, waste disposal, and energy are generally higher in the subject refineries than they are in refineries elsewhere. Second, and more critical, is the fact that the baseline emissions are generally much lower from the SCAQMD area refineries than they are from refineries of comparable processing capacity that have been the subject of studies in other locations. As a result, the opportunities to capture SOx are significantly more limited and the costs of a major capital project are necessarily distributed among a smaller quantity of emission reductions. The larger costs of the capital project coupled with the smaller opportunities for emission reduction result in inevitably higher per ton costs for emission reductions. As such, per ton cost estimates for SOx emissions reductions, which have been the result of studies in other refineries, are irrelevant to the current study. Imposition of those per ton cost estimates on the South Coast refineries is not supported by data and is likely to lead to erroneous conclusions.

II. FACILITY & EMISSIONS PROFILES

A. GENERAL FACILITY & EQUIPMENT DESCRIPTIONS

Each of the six South Coast refineries processes a variety of feedstocks—typically crude oils—into several hydrocarbon products. The most common of the latter are automotive (gasoline and diesel) and aviation (e.g., jet) fuels, all of which have tight upper limits on the allowable sulfur contents. (A broad spectrum of other products and by-products is also produced, but they are of lesser volume and/or importance than the preceding transportation fuels.) However, the refinery feeds—with quantities in the many thousands of barrels per day—often contain significant percentages of sulfur. The average weight content of sulfur in common domestic and Western Hemisphere crude oils commonly exceeds 1%, and can occasionally be above 3%. The average production of elemental sulfur from each of the refineries is greater than 200 long tons per day.[1]

Given that the maximum permissible sulfur levels in the above-mentioned transportation fuels are measured in at most the 10's of parts per *million*, it's clear that sulfur removal from the crude oil (and other) refinery feeds must be extremely thorough. The primary method for achieving that feed desulfurization is by hydrogenating (more often referred to as "hydrotreating") the sulfur in the process stream; in other words, elemental hydrogen is encouraged to bond with the sulfur atoms in a 2:1 ratio, creating hydrogen sulfide (H_2S). (Optimizing that process ordinarily requires high pressures and temperatures, plus the presence of a suitable catalyst, as well as an abundance of hydrogen.) Subsequently, the gaseous H_2S (along with a host of other low molecular weight and volatile substances) is separated from the main hydrocarbon stream, leaving it with a much lower sulfur content than was in the feed.

Crude oil entering a refinery is distilled and separated into various fractions by boiling range. These include from the lightest (lowest boiling point) to the heaviest (highest boiling point) gas, naphtha, kerosene, gas oil, residual fuels, and coke. Gasoline is made from naphtha, and fuel oils and lubricants from the gas oil fraction. The natural split from distillation is seldom the same as the desired product slate. A number of refinery conversion units are employed to change the natural mix.

One of these is the fluidized catalytic cracking unit (FCCU, or cat cracker). It takes a feed in the gas oil range and converts it into lighter products, primarily gasoline. Gas and some heavies, including petroleum coke, are also formed. What is not separated from the gas to become useful product becomes refinery fuel gas (RFG). RFG is addressed in Module 2.

The FCCU breaks down a hydrocarbon feed at high temperature in its reactor vessel containing a fluidized bed of finely divided silica-alumina cracking catalyst. The catalyst circulates continuously between the reactor and the regenerator vessel. In the

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[1] This number was provided to AEC directly by the refineries during the site visits in September-October 2008.

regenerator, the coke laid down on the circulating catalyst is burned off to restore the catalyst's activity and to provide the requisite energy for the process.

Sulfur originating in the crude oil finds its way into the cat cracker's liquid products, overhead gas, and coke. This sulfur is reduced by hydrotreating the cat cracker feed. Increasing the severity of hydrotreating can be construed as a process that results in a lower sulfur level in the RFG. However, hydrotreating affects sulfur levels in the coke-on-catalyst (the coke is not part of the RFG system), which is burned in the cat cracker regenerator. The sulfur subsequently ends up as SOx in the regenerator flue gas and may indirectly affect the expected efficiency of a flue-gas scrubbing device on the FCCU regenerator. The FCCU is the biggest <u>single</u> source of atmospheric pollution in an oil refinery, primarily from sulfur oxides (SOx) and particulate matter (PM). On a lesser scale, half of the NOx (oxides of nitrogen = nitric oxide, NO, + nitrogen dioxide, NO_2) in a refinery is estimated to originate from the FCCU.

Average daily SOx emissions from Los Angeles area refineries during 2005 are listed in Appendix A, Table A-1**.** Although combustion of refinery fuel gas (RFG) in boilers, heaters, etc. (the Others Category) and the effluent from the sulfur recovery unit (SRU) are also important sources of atmospheric contamination, a large proportion originates from the FCCU alone. Hence, the greatest reductions in SOx are to be realized from treatment of the cat cracker.

Refinery Fuel Gas (RFG) is a leftover stream containing gaseous-phase constituents judged not to be able to be recovered economically for sale as products. It can consist of numerous hydrocarbons, hydrogen, carbon oxides (CO and CO_2), and various sulfur species, such as hydrogen sulfide (H_2S) (primarily), carbonyl sulfide (COS), carbon disulfide (CS_2), and possible mercaptans (RSH). Thioethers (RSR') and disulfides (RSSR') may also be present. The sulfur species originate from the sulfur contained in organic compounds in the crude oil processed by the refinery.

The RFG is burned for energy in lieu of recovery as useful products. It is consumed in the refinery's boilers, furnaces, and fired heaters to make steam or raise the temperature of refinery process streams. It may be burned locally in the unit where it is generated or sent to one or more refinery fuel headers. In these days of environmental awareness, the sulfur content must be removed or reduced before combustion or scrubbed out of the resulting flue gas. Much of the RFG to be treated results from hydrodesulfurization, or hydrotreating, of refinery feed and/or product streams.

Typical treatment consists of absorption of H_2S in a continuous regenerable amine process using a reagent such as monoethanolamine (MEA), diethanolamine (DEA), methyl-diethanolamine (MDEA), or diglycolamine (DGA). The cleaned gas goes on to become fuel. When the so-called *rich* amine solution is steam stripped in a separate regenerator vessel, the effluent gas, concentrated in H_2S, is sprung from solution, and the resulting *lean* amine solution returns to the absorber vessel for another pass.[2]

The second category on which the team focused its attention was that of large, stationary combustion equipment. Examples of such items include heaters, furnaces, boilers, and cogeneration units. In most cases within the subject refineries, the fuels used for those pieces of equipment were predominantly refinery fuel gas, although quite a few are fired (in part or wholly) using natural gas. (None of the equipment seen during the visits is fueled with liquid feeds—at least during non-emergency operation. Hence, all of the analyses were predicated on gaseous fuels.) Since any sulfur species contained in the gaseous fuel is ultimately oxidized and exhausted as SOx, the equipment that (a) has a high thermal output, (b) is in continuous or near-continuous service, and (c) is fueled entirely—or mostly—with sulfur-rich refinery fuel gas is a potential target~~s~~ for a SOx reduction study. (Presently, none of the refineries incorporate post-combustion treatment for removal of SOx, although a fair number of installations have been made to remove NOx from the flue gas streams of select items.) In the particular case of this module, the team evaluated up to ten of the very largest SOx emitters in each refinery.

The overhead gas is sent to the refinery's sulfur plant, or sulfur recovery unit (SRU), for recovery of the sulfur as saleable yellow sulfur after it is condensed. It can also be made into sulfuric acid. The residual gas is incinerated before being released to atmosphere since the sulfur oxides (SOx) formed upon combustion constitute less of an air pollution, health, or safety problem than the raw unburned H_2S and other sulfur species escaping the recovery process.

The SRU nowadays consists of the Claus process, which has been around since 1885, plus what is termed a *tail gas process* to treat the Claus process effluent. One-third of the H_2S entering the Claus plant is combusted to SO_2. The SO_2 in turn is reacted over a catalyst with the remaining H_2S to form elemental sulfur (S). Alumina (better) and bromide catalysts are cited. Reactions are as follows:

$$H_2S + 3/2\ O_2 \rightarrow H_2O + SO_2$$

$$SO_2 + 2\ H_2S \rightarrow 2\ H_2O + S$$

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[2] Notwithstanding the popularity of an amine process, other possibilities exist such as hot potassium carbonate, Rectisol (methanol-based), Selexol, and Sulfinol. The SCAQMD's RFP also mentions Merox. Another technology that could be used in combination with sulfur removal from RFG is deeper hydrodesulfurization of refinery feedstocks. Chevron was issued a patent in 2005 for a process to desulfurize crude oil.

Removal of H_2S in the Claus plant is quoted in the range of 90-96%, indicated to be limited by equilibrium. The tail gas process works on the remaining 4-10%.

One such process is SCOT, offered by Shell. Other competing processes are also available. In the SCOT process, hydrogen is added to convert any COS and CS_2 present to H_2S using a titanium catalyst. The H_2S is absorbed in an amine solution; the H_2S stripped off during regeneration is recycled to the front-end of the Claus plant. Addition of a tail gas process is said to boost overall sulfur recovery in the range of 99-99.9%. But at the very end of most TGTU processes, the effluent (non-recoverable and non-recyclable) gas stream is disposed of to the atmosphere by either free venting or by combustion in a thermal oxidizer or incinerator. If combusted the sulfur in that effluent gas is oxidized to SOx. Even with an overall conversion efficiency that exceeds 99%, any SRU/TGTU of the size seen in the South Coast area refineries is going to emit large amounts of SOx to the atmosphere because of the considerable quantities of sulfur (principally as H_2S) that enters it.

Hence, as outlined above, the refineries collectively have a large number of combustion equipment packages (from FCCs to TGTU incinerators and fired process heaters) with exhaust stacks, out of which large quantities of SOx (originating as various sulfur compounds in the gaseous feeds) are discharged to the atmosphere. It's important to remember that in 2005, the cumulative SOx emissions from boilers, heaters, and other similar fired equipment reached approximately 3 tons per day. In that same year, the refineries measured SOx emissions from FCCUs at slightly more than 3.5 tons per day. Therefore, this module obviously contains potentially very good opportunities for post-combustion (i.e., scrubber) treatment to reduce overall SOx emissions.

B. EMISSION PROFILES IN 2005 & 2008

The total reported SOx emissions from the six subject refineries since 2004, and up to the present, spans a range from about 0.8 to nearly 2 tons/day per refinery. The estimated numbers are as shown below (in Figure 2.1), listed in ascending order based on 2005 totals.

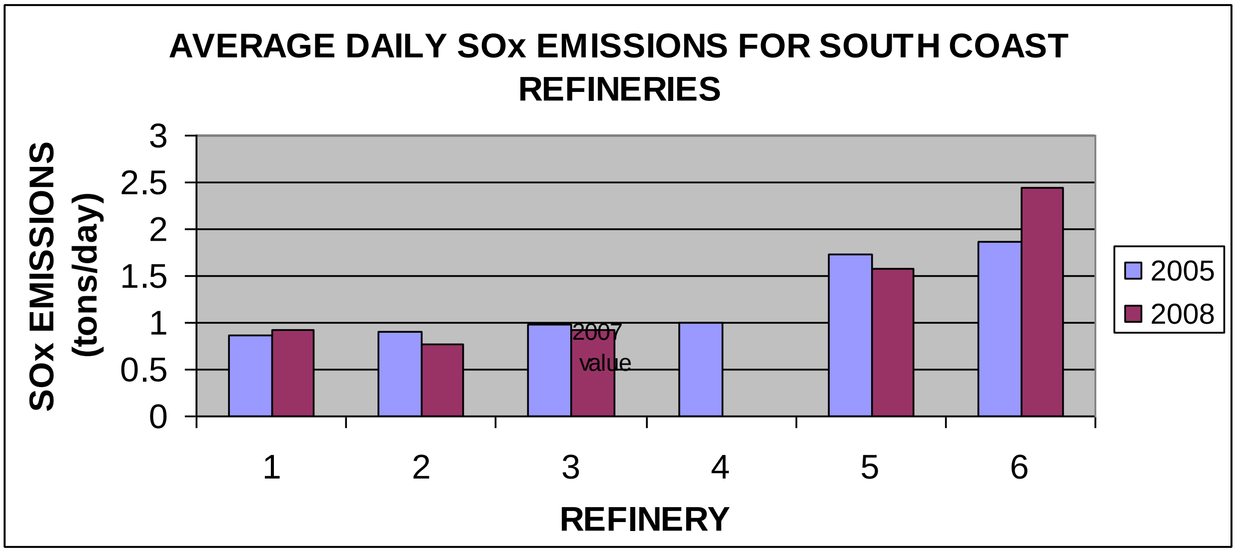


Figure 2.1: Average daily SOx emissions for South Coast refineries in 2005 and 2008 (where available).

There is a decline in emissions from 2005 to 2008 (based on partial year-to-date totals made available to the study team), at least with respect to some of the refineries. This is definitely encouraging, and probably the direct result of multiple efforts being made to achieve better environmental controls. For example, one of the refineries recently installed and commissioned a wet gas scrubber for its FCC regenerator exhaust; likewise, the increased application of SOx-reducing catalyst additives to the FCC units in some of the refineries has had beneficial impacts on the SOx totals.

When it comes to the question of how individual system or point sources of SOx contribute to the totals, the picture is a little different for each refinery. In almost all cases the FCC is the biggest single emitter. Typically, after that, the categories of (a) fired equipment (i.e., heaters, furnaces, boilers, and cogeneration units) and (b) sulfur recovery units are the next most significant emission categories. (In addition to the information furnished above, see the SCAQMD Preliminary Draft Staff Report, Table 4-2, for a tabulation showing that the SOx emissions from just the largest emitting boiler/heaters were approximately 0.91 tons per day in 2005, 0.98 tons per day in 2006, and 1.11 tons per day in 2007.)

III. CONTROL TECHNOLOGIES—FEASIBILITY ANALYSIS

A. CRITIQUE ON SCAQMD PRELIMINARY DRAFT STAFF REPORT

The "Preliminary Draft Staff Report for SOx RECLAIM (Part 1)", dated 3 April 2008, was an immensely informative document. Clearly described therein were probably the most obvious—if not also some of the most important—candidate technologies for SOx reduction in each one of the systems being investigated by AEC. Moreover, the report was exceedingly helpful in its identification of certain manufacturers and their respective packages for the referenced technologies. Yet other valuable inclusions are the comparisons of efficiency ranges for treatment types, along with very approximate effectiveness ratios (i.e., cost per ton of SOx removal).

These approximations were based on detailed studies of implementations of the measures similar to those studied in this report, but based on conditions at other facilities with similar processing capacity. The effectiveness ratios, however, depend on the total achievable SOx reduction capacity. The refineries examined in the benchmark study, referenced in the draft report, had combined FCCU emissions in excess of 45,000 TPY SO_2 in 2002 and were projected to be below 5000 after implementation of control measures. For the South Coast Air Basin, the refineries' baseline emissions for the FCCUs totaled less than 1300 TPY. Similarly, for the study from which cost effectiveness ratios in the draft report were obtained, the total facility SOx emissions were over 58,000 TPY, but the total emissions in the South Coast Air Basin were under 4000 TPY. The study that produced the cost effectiveness ratios reported in the draft report was able to spread equipment costs over a substantially larger body of emission reductions, so the cost effectiveness ratios for that study are not expected to be a good indication of the cost effectiveness ratios for the South Coast Air Basin facilities. Also vital are the facility-specific differences that cannot be understood simply by comparing processing capacity and other high-level metrics. The importance of facility specific study in any effort to produce accurate cost effectiveness ratios must not be understated.

Nonetheless, the April report was an excellent starting point for the evaluations. The background information that it contained was extremely helpful, and the technologies that it discussed were among the most effective SOx control technologies available today. While much of the cost estimation was done at a very high level and the cost effectiveness ratio estimates are not directly applicable to the South Coast refineries, the April 2008 report has been a valuable resource for the current study. The need for more detailed study focused on the South Coast refineries does not diminish the value of the April 2008 report.

The April 2008 report was neither intended to be, nor was it, used as a completely prescriptive guideline for the work. The basic technologies enumerated in that document were fully explored, but the engineering efforts didn't stop there. The general principle for this study is simply stated as follows: The goal was to identify and quantify (in terms of cost and benefits) the best technologies for SOx reduction in the refineries, provided they were practical and proven. In doing so, certain named approaches were considered. However, beyond that, AEC was tasked with evaluating the existing commercially viable control technologies, starting with the most effective control technology, and making recommendations on various technologies that could potentially be used to achieve additional emission reductions. In that vein, the AEC team members conducted very broad-based research and brainstorming to come up with the best opportunities.

B. LITERATURE RESEARCH ON CONTROL TECHNOLOGIES

The extent of the team's general research was initially limited to the acquisition of basic data on the primary SOx reduction technologies. That data was used to generate "briefing sheets" and field checklists taken to the refineries for the initial visits. The AEC engineers were, therefore, able to maximize the effectiveness of their times in the refineries. That research, fortunately, largely constituted just the updating of information and contacts that had already been accumulated by AEC and its parent company, IDOM, over the past few decades of work in refineries and power plants. Through those previous projects by AEC and IDOM—and others which were contemporary, for a variety of worldwide clients—we had access to reliable and recent applications of proven technologies for the reduction of SOx emissions. Particular examples of those technologies were both wet and dry scrubbing, as well as the latest generations of gas treating methods and the variants to the traditional Claus/SCOT sulfur plants. Nevertheless, in spite of this extensive resource base, the team validated all the pertinent details and, of course, updated them to the relevant design parameters under which the South Coast refineries' units were functioning at that time.

Once the trips were completed, AEC screened and prioritized all of the SOx reducing technologies for particular systems and equipment items. This was a very extensive task, requiring a huge amount of particular data for the candidate packages. The veins of AEC's research included media such as: periodicals; textbooks; the Internet; internal corporate files; telephone calls; and manufacturers' literature.

Assimilating all the technology-related information helped the evaluators compile all the relevant features and impacts of each candidate technology, relative to its intended installation point. And, as a consequence, AEC was able to present a realistic assessment of both (a) the costs of installation and operation, and (b) the net operations impacts (including, most importantly, the expected SOx reductions for the stipulated levels of controls, along with any changes to other pollutant emissions) for the technologies under consideration. With that information available, all the stakeholders are better positioned to make the important decisions about what technology retrofits and additions are the most reliable, effective, and affordable.

Brief discussions of potentially applicable technologies are presented in the following paragraphs:

GAS SCRUBBING

The exhaust, flue or process gases exiting any of the FCCUs, Fired Equipment, SRUs or TGTUs are a primary emission source of SOx. Due to the high volume of gases, a reasonable approach to reduction is to treat the gases in some way as to reduce, eliminate, or change the sulfur bearing species and separate those molecules from the stream for reclamation or further treatment. Two main scrubbing technology types exist for this and are normally classified as wet or dry gas scrubbing. In addition, the wet scrubbing technologies are distinguished as being either regenerative (that is, the scrubbing aid is treated to release the captured species and then reused) or non-regenerative (that is, the scrubbing agent, normally water in some form, is the final discharge stream and contains the sulfur bound up in some chemical form such as with caustic or lime).

REGENERATIVE WET GAS SCRUBBING (RWGS)

Regenerative wet gas scrubbing (RWGS) was studied as an option for the sulfur plant tail gas. RWGS systems are favorable to non-regenerative wet gas scrubbing systems when the SOx concentration in the feed streams is particularly high. In these cases, the reduction in waste materials compared to non-regenerative systems and the recovery of saleable elemental sulfur allow a refiner to offset the larger costs of the equipment package.

Regenerative wet gas scrubbing was studied as an option for emissions control from the SRU/TGTU along with non-regenerative wet gas scrubbing because the concentrations of SOx in the exhaust streams are, in general, higher in those units than in other units. It is here that there is an expectation that regenerative wet gas scrubbing will be most competitive when compared to non-regenerative wet gas scrubbing.

For several refineries, regenerative and non-regenerative wet gas scrubbing systems were compared head-to-head for emission reductions at the SRU/TGTU. In all of these cases, it was found that the removal capabilities of regenerative systems are no better than those in non-regenerative systems. In addition, in all cases where the technologies were compared head-to-head, the costs of removing SOx in a regenerative system were higher than the costs in a non-regenerative system. This is a simple artifact of the nature of emissions in the SCAQMD area refineries. They are already quite low by industry standards. In other locations, where emissions are higher, a regenerative system may be more attractive. Because RWGS systems could not be shown to be less costly or more effective than non-regenerative wet gas scrubbing systems for the SRU/TGTU in the SCAQMD area refineries, it was not studied in other applications, where the RWGS is expected to be less competitive with a non-regenerative system. At the heart of the regenerative wet gas scrubbing process is an amine absorber and regenerator package. The amine in the absorber is highly selective for SO_2 as compared to CO_2. The sour gas from the regenerator is recycled back to the sulfur recovery process for additional conversion.

The single RWGS manufacturer chosen for detailed analysis in this study is Cansolv, of Montreal, Canada. The Cansolv SO_2 scrubbing system was first invented by Union Carbide in 1988. The technology was then purchased in an employee buyout in 1997 (Birnbaum, 2008).

Figure 3.1 depicts a general block flow diagram for a Cansolv regenerative wet gas scrubber for stack treatment in an SRU/TGTU.

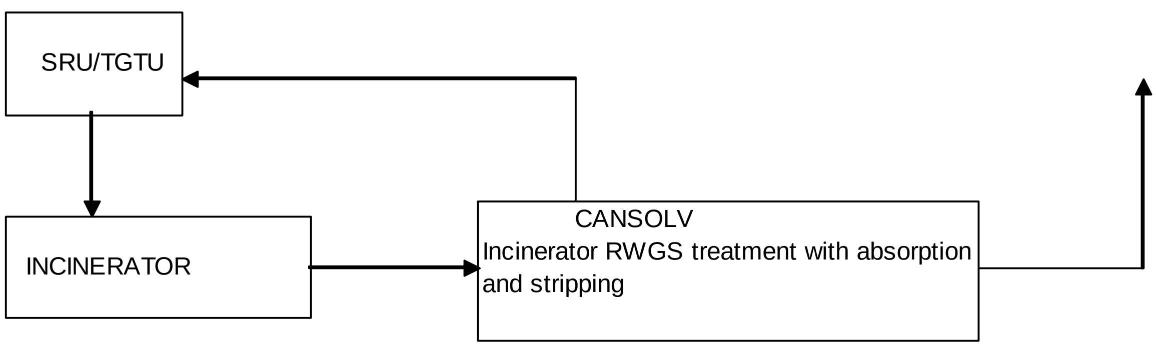


Figure 3.1: Cansolv block flow diagram for stack treatment in the SRU/TGTU

NON-REGENERATIVE WET GAS SCRUBBING (NWGS)

Non-regenerative wet gas scrubbing (NWGS) was also studied. These units are typically less expensive to install than a regenerative system since they generally have significantly less equipment and are only discharging a liquid/solid waste stream, but they consume relatively large amounts of water and produce waste water.

In a non-regenerative wet gas scrubbing process, a vapor to be scrubbed is contacted with a liquid stream (usually aqueous). The liquid stream contains a reagent that reacts with SO_2. There are a number of reagents that can be used with non-regenerative wet gas scrubbing systems. Caustic (NaOH) is often selected, though alternatives exist. Some common alternatives are soda ash (Na_2CO_3), lime (CaO), and limestone ($CaCO_3$). The reaction products are generally salts that must be carried away with a waste water stream. Fresh reagent and fresh water are fed to the unit to replace the water lost as waste water and the reagent consumed in the reaction.

There are a number of advantages to wet gas scrubbing. Operation of the package is not particularly complex, and the process hazards that accompany it are typically manageable in a refining environment. In addition, such units are very effective at removing SOx from gas streams and can also reduce emissions of particulate matter into the air.

However, there are also a number of disadvantages to wet gas scrubbing. In the case of caustic treatment, sodium sulfite and sodium bisulfite salts are created. With these salts comes a chemical oxygen demand (COD) in the waste water. Prior to discharge, further treatment may be required to address concerns related to the sulfite and bisulfite salts. Also, a large plume often forms as water is evaporated in the non-regenerative wet gas scrubber. This is not only unsightly, but is also a source of water loss for the refinery.

The NWGS manufacturers adopted as the options for this study are BELCO, MECS, Alstom, and Tri-Mer. BELCO, currently headquartered in Parsippany, New Jersey, was founded in 1968 as a subsidiary of Foster-Wheeler. In January, 2006 BELCO became wholly owned by DuPont. MECS has a NWGS technology developed in the 1970s when MECS was a Monsanto subsidiary. Since 2005, MECS has been an independent company and is located in St. Louis, Missouri (Kixmiller, 2008). According to information on its website, Tri-Mer is headquartered in Owosso, Michigan and has been providing design/build services since 1960. The experience with NWGS installations for each of these companies is discussed in Section C, below.

Figure 3.2 is a schematic diagram for the DynaWave non-regenerative wet gas scrubber. Figures 3.6 and 3.7 depict a BELCO wet gas scrubber. (The general location of the scrubber installation in the FCCU is depicted in Figures 3.4 or 3.5 above.)

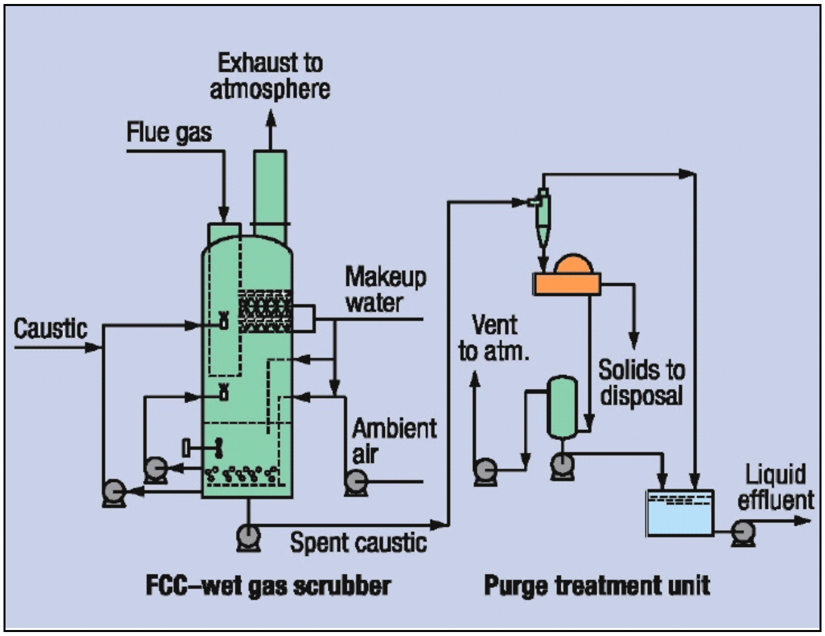


Figure 3.2: DynaWave process flow diagram taken from http://www.mecsglobal.com/MECS/images/Brochures/Dynawave/HP_9_05_MECS2.pdf (reprinted from Hydrocarbon Processing, Sept. 2005 issue, pgs 99-106)

Figure 3.3 is a picture of the DynaWave scrubber.

Figure 3.3: Picture of DynaWave regenerative wet gas scrubber taken from http://www.mecsglobal.com/MECS/images/Brochures/Dynawave/HP_9_05_MECS2.pdf (reprinted from Hydrocarbon Processing, Sept. 2005 issue, pgs 99-106)

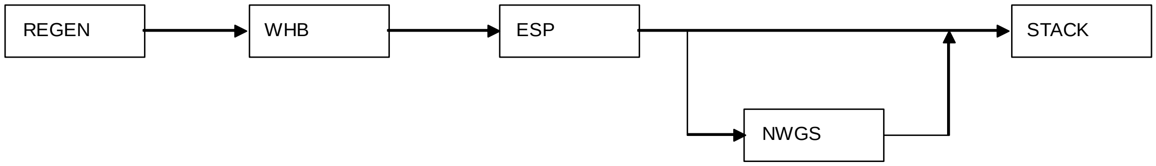


Figure 3.4: Block flow diagram depicting an FCCU wet gas scrubber application where the existing stack is modified

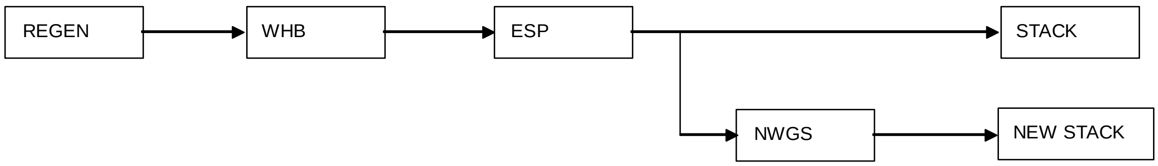
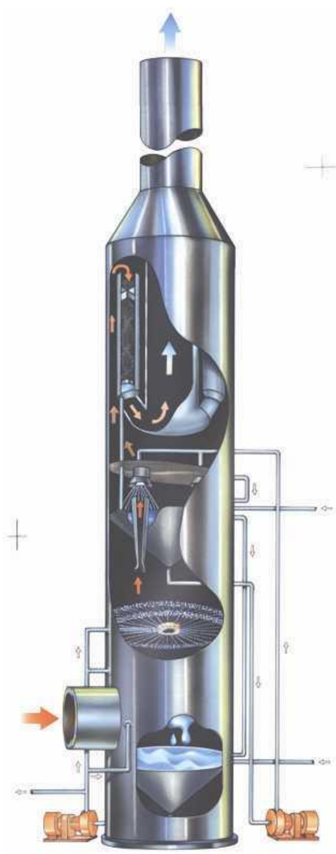


Figure 3.5: Block flow diagram depicting an FCCU wet gas scrubber application where a new stack is installed and the existing stack is bypassed




Figures 3.6 and 3.7: Diagram and photo of BELCO wet gas scrubber taken from http://www.belcotech.com/products/edv.html

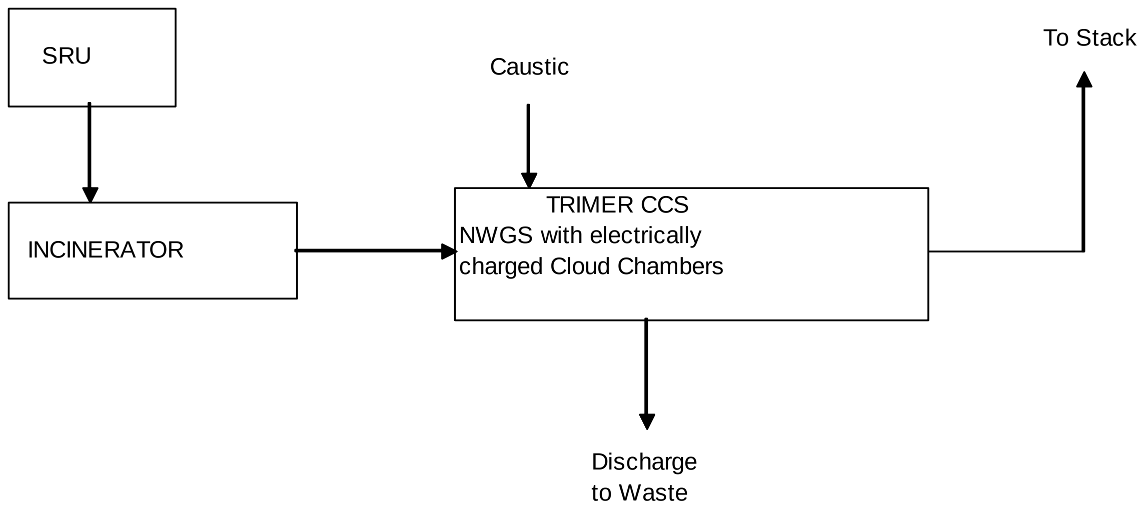


Figure 3.8: Block flow diagram of Tri-Mer wet gas scrubbing technology for stack treatment in the SRU/TGTU

Figure 3.9 depicts a block flow diagram of the Tri-Mer non-regenerative wet gas scrubber for the stack treatment of a boiler or heater. This particular diagram depicts an application where the existing stack is modified, not replaced.

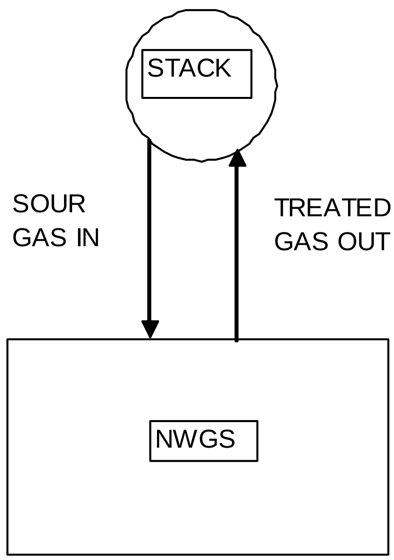


Figure 3.9: Block flow diagram of Tri-Mer wet gas scrubbing technology for refinery boiler or heater stack treatment

Figure 3.10 is a picture of the Tri-Mer cloud chamber technology.

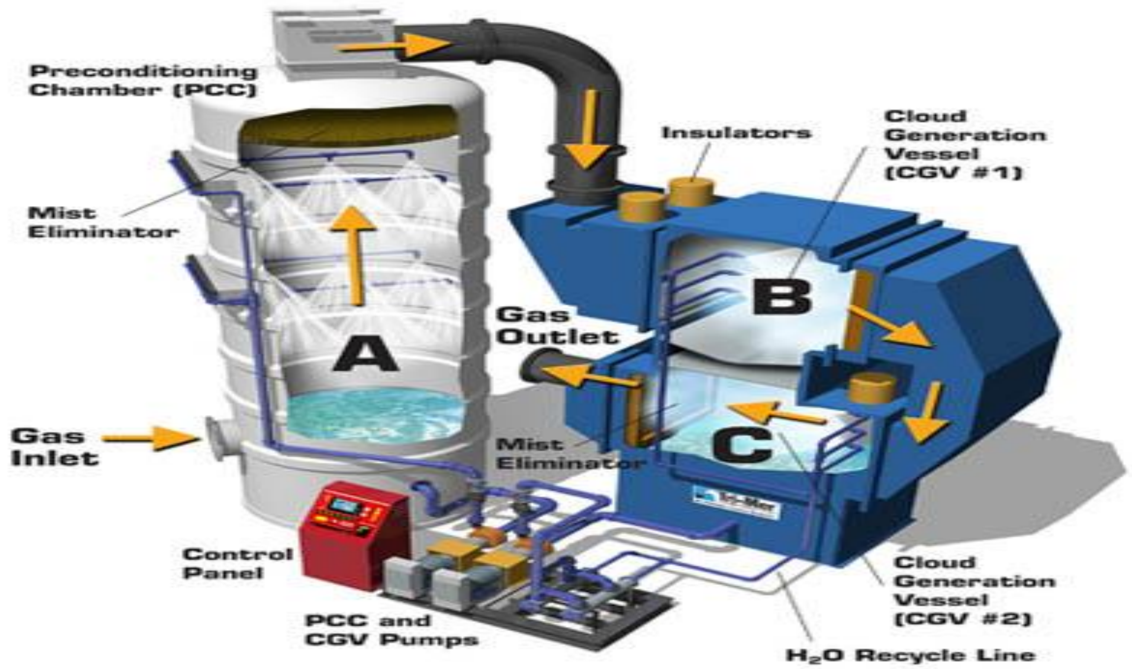


Figure 3.10: Picture of Tri-Mer Cloud Chamber technology taken from http://www.tri-mer.com/wet_scrubber.html

DRY GAS SCRUBBING (DS)

In a dry gas scrubbing system, a slurry of reagent (often lime) and water is mixed and contacted with a flue gas. The hot gas will facilitate the desulfurization by both simultaneously driving off the water from the slurry as well as enhancing the chemical reaction of the sulfur species with the lime. The SOx in the flue gas reacts with the reagent and forms a solid product. In the case of lime reagent, calcium sulfate and calcium sulfite are formed. The product of the reaction is a solid and must be removed from the flue gas before emission to the atmosphere. This is usually accomplished using either a bag house or an electrostatic precipitator (ESP). The solid product can then be collected and removed from the refinery as a solid waste.

There are some important advantages of dry gas scrubbing over wet gas scrubbing. First, there is no waste water discharge from a dry gas scrubbing system. This lack of waste water discharge can be a major advantage in sites where water is in short supply or water treatment is very expensive. In addition, the main product of the reaction is calcium sulfate. Whether this calcium sulfate will be a saleable product remains to be seen. However, the power industry supplies synthetic gypsum from its flue gas desulfurization

(FGD) processes to the wallboard industry today. There is likely potential for refineries to also find applications for products from their dry gas scrubbers.

Despite the numerous advantages of dry gas scrubbing over wet gas scrubbing, there are a number of very compelling disadvantages. First, the refinery will need to handle solids, at both the input to the process, in the form of lime, and at the output from the process, in the form of calcium sulfate and calcium sulfite. This solids handling is generally more complex than liquids handling for a refinery. In addition, the capital investment is expected to be substantially higher and the removal efficiency is expected to be lower for dry scrubbing systems than it is for wet gas scrubbing systems. Also, operation is potentially more complex and maintenance more frequent for dry gas scrubbers. The net reduction in particulate emissions is also lower for dry vs. wet gas scrubbing.

For this study, Hamon Research Cottrell, with its US headquarters (Hamon USA) in Somerville, New Jersey, was chosen as the representative option for dry gas scrubbing opportunities. Hamon has been producing dry FGD technologies since the late 1970s (http://hamon-researchcottrell.com/Prod_FlueGasDry.asp, 2008).

Figure 3.11 depicts a process flow diagram of the Hamon dry scrubber.

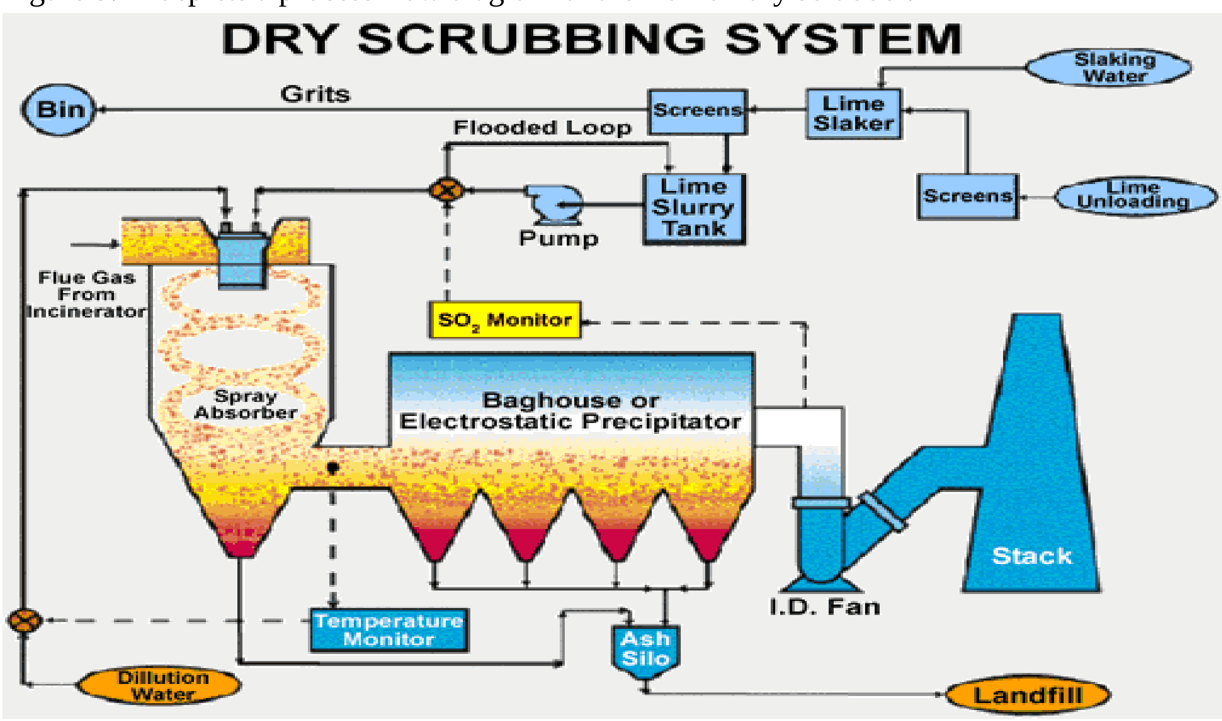


Figure 3.11: Schematic diagram of Hamon dry scrubbing technology taken from http://www.hamon-researchcottrell.com/Prod_FlueGasDry.asp

Figure 3.12 is a picture of the Hamon dry scrubber. (The general location of the installation in the FCCU is depicted in either Figures 3.4 or 3.5, above.)

Figure 3.12: Picture of Hamon dry scrubber taken from http://www.hamon-researchcottrell.com/Prod_FlueGasDry.asp

SEAWATER WET GAS SCRUBBING (SGS)

A special type of wet gas scrubbing, seawater gas scrubbing (SGS), has been found to be particularly attractive at some locations from a cost effectiveness point of view. Seawater wet gas scrubbing is a type of wet gas scrubbing where sea water is used as the scrubbing agent. Because seawater is typically slightly alkaline, it has a natural ability to neutralize acidic gases, such as SOx, which is absorbed by the seawater and removed from gas streams. Once absorbed into the seawater, the water is treated in order to convert the absorbed SOx into sulfates, a relatively harmless form of sulfur. The water is then discharged back into the ocean.

This process is licensed by Alstom (www.no.alstom.com, 2008), with over 40 years of experience and thirty SGS installations. The first Alstom seawater flue gas desulfurization (FGD) plant was installed in 1968. According to a brochure titled, "Operation and Development since 1968 ALSTOM Seawater FGD", the seawater scrubber is capable of removal efficiencies greater than 99%.

SOx removal efficiency is equivalent to that of non-regenerative fresh water scrubbing. However, although technically feasible, implementation of SGS requires both access to sufficient seawater and the ability to obtain the necessary permits for seawater intake and the discharge of scrubber effluent and its implementation in the South Coast Area is therefore unlikely. The study team is not specifically advocating this technology, and SGS was not recommended as a selected treatment measure for any facility in this study. It would be up to an interested refinery to investigate this system adequately before attempting to implement it.

C. IDENTIFICATION OF RELEVANT VENDORS AND CONTACT STATUS

Insofar as the wet and dry gas scrubbing technologies are concerned, information provided by SCAQMD was very helpful in identifying some of the vendors that were considered in this study. Contact was made with all vendors listed in the SCAQMD preliminary report and a number of vendors that were not listed. After initial discussions with vendors, careful reviews of various resources were conducted: literature provided by vendors; the April 2008 Preliminary Draft Staff Report; in-house files; public domain articles and reports; and conversations with industry experts. At that point, five different technology providers were selected for detailed analysis of installation and operation economics. The technology providers selected for each application are summarized in Table 3.1.

Table 3.1: Application-specific technology providers selected in cost analysis study. The technology types are abbreviated as follows: non-regenerative wet gas scrubbing (NWGS), dry scrubbing (DS), regenerative wet gas scrubbing (RWGS), and seawater wet gas scrubbing (SGS).

System / Unit	**Technology Type**	**Vendor / Licensor**
FCCU	NWGS	BELCO
		MECS
	DS	Hamon
	SGS	Alstom
SRU/ TGTU	RWGS	Cansolv
	NWGS	Tri-Mer
Boilers & Heaters	NWGS	BELCO
		Tri-Mer
	DS	Hamon

The providers listed in Table 3.1 were selected because they have substantial experience in SOx control in industrial applications, their technologies are effective at controlling SOx emissions, and the cost information provided has enabled accurate estimation of the costs of installing these technologies in oil refineries. Moreover, they appear to be among the most competitive in the industry in terms of performance and cost affordability.

As seen in the table, above, the technology provider evaluated as part of this study for regenerative wet gas scrubbing systems is Cansolv. The application of their technology was in the SRU/TGTU. With 9 operating plants, and 5 licensed units (Birnbaum, 2008), the capabilities of the Cansolv system have been demonstrated in the petrochemical and chemical industries. In an e-mail from Rick Birnbaum it was stated that "CANSOLV Scrubbing Technology can reduce SO_2 emissions to less than 10 ppmv." He went on to state the following: "CANSOLV SO_2 scrubbing is most justified for high SO_2 inlet concentrations. We would be best applied as a standalone tail gas unit rather than a polishing unit. A CANSOLV application with a design inlet of 50 ppm SO_2, that targets 10 ppm outlet SO_2 specification, would not be of economic interest to the client. A NaOH scrubber would be more attractive".

Non-regenerative wet gas scrubbing has been studied for applications in the FCCUs, SRU/TGTUs, and heaters and boilers in the SCAQMD area refineries. In particular, systems by BELCO and MECS were studied for the FCCUs. For the SRU/TGTUs, Tri-Mer's technology was considered. In the case of heaters and boilers, BELCO's technology was the NWGS candidate.

Each of these companies has experience in the chemical and petrochemical industries. MECS developed their DynaWave technology in the 1970s and has over 300 installations worldwide (Kixmiller, 2008). Specific examples are two Sinclair oil refineries in Wyoming. According to a published paper titled, "DynaWave Wet Gas Scrubbing: A New Alternative for Claus Unit Tail Gas Clean-Up", written by Steven F. Meyer, Ed Juno, Nick Watts, and Cristina Kulczycki, each refinery installed a DynaWave scrubber for SRU/TGTU stack treatment. The results of stack testing was a 99.99% sulfur removal. The DynaWave mitigates the effluent COD by injecting air into the sump of the vessel in order to oxidize the sulfites. The sump is also designed to allow adequate retention time for the oxidation to take place. As a result, the effluent water can be discharged directly to the wastewater treatment plant, provided the COD levels are continuously monitored and maintained within an acceptable range. According to the paper, the COD at the Casper, WY refinery ranged between 50 and 150 mg/l.

Tri-Mer has published performance data in its "CCS Product Bulletin" for its Cloud Chamber technology in a number of different combustion applications (www.tri-mer.com, 2008). In a phone conversation with Kevin Moss of Tri-Mer (Business Development Director), and Rod Graveley of Tri-Mer (Technology Director), it was stated that there are no examples of Tri-Mer applications in refineries; however, the Cloud Chamber technology has been thoroughly proven in various diesel and coal combustion applications. This is the main reason why Tri-Mer was considered for refinery boilers and heaters stack treatment and SRU/TGTU's. Tri-Mer can guarantee a minimum 99% SOx and particulate removal efficiency for inlet concentrations ranging from 10-450 ppm and inlet temperatures ranging from 300-1000 deg F. The Tri-Mer Cloud Chamber technology offers a minimum 95% complete effluent oxidation to sulfate as a result of a significant retention time (approximately 6 seconds). If operated correctly with the optimal retention time and liquid to gas ratio, the Cloud Chamber technology will oxidize 100% of the sulfur compounds to sulfates.

BELCO (DuPont) has more than 65 EDV wet scrubbing systems in refineries, at least 61 of which are in FCCU applications and 156 EDV wet scrubbing systems in other applications. BELCO also has examples of EDV applications for SRU/TGTU and refinery boilers and heaters (DuPont Power Point Presentation, 2008). In a letter sent to ETS from Nick Confuerto, Vice President, Technology, Sales & Marketing of BELCO, it was confirmed that the guaranteed SOx outlet concentration based on the refinery-specific information provided would be 5 ppmv. The EDV utilizes a Purge Treatment System to decrease the COD and suspended solid content of the effluent. A clarifier is used to collect the solids and then they are filter-pressed and disposed. The oxidation is facilitated in a tower with air forced through the effluent to convert all sulfites to sulfates. After these two steps the effluent is safely discharged to the waste water treatment plant.

The dry scrubbing technology evaluated in this study is Hamon's. It was evaluated for both FCCU and heater and boiler applications. According to information on its website, Hamon FGD technologies are installed in twenty countries and treat over 65,000 MW of power generation capacity. Hamon also has a long standing relationship with refineries world wide with over 100 ESP installations on FCCUs. There is no example of a dry scrubber installation in a refinery. However, the level of experience in FGD and general refinery applications is adequate to describe the technology as field demonstrated. In an email sent to AEC, a Hamon Research employee quoted a 90+% removal efficiency for streams with 300-400 ppmv SOx. Because flue gases in the South Coast refineries are typically below this range, the removal percentage is expected to be below 90% in most cases. Typically, it is governed by the SOx outlet concentration, which is not forecasted to fall below 10 ppmv on a guaranteed basis. Hence, the removal percentage for Hamon's dry gas scrubber is application-specific in these refineries and generally will be below 90%. One additional consideration for all types of dry scrubbers is the issue of solids handling. The effluent gas will have considerable particulate matter that must be removed. Therefore it is necessary to install some type of an ESP or baghouse downstream from the scrubber. The solids handling equipment will need to collect both dry particulate matter from the scrubber and particulate from the FCC. This introduces additional complexity with respect to available plot space and capital expenditure.

D. DISCUSSION ON CONTROL TECHNOLOGIES & POTENTIAL EMISSIONS REDUCTIONS

1. FCCUs

Because the FCC units are the primary sources of SOx from all but one of the South Coast refineries, reducing emissions from the FCCs has been one of the focal points of this study. (The refinery for which the FCC is not a focal point has recently installed a wet gas scrubber to control emissions from its FCC.). The overall *process* features of the individual refinery FCC plants are quite similar. The reactors, regenerators, catalyst handling, air charging, and other basic elements are essentially the same at all six locations. But the treatment equipment on the regenerator gas outlets is very different. For example, most of the refineries currently rely on electrostatic precipitators (ESPs) to control particulates, whereas one site employs a new wet gas scrubber. Other differences among the refinery FCC installations are also important, even if not as dramatic.

With reference to the present level of emissions controls in the FCCs, the current technology varies from a wet gas scrubber—a technology widely viewed to be the ultimate particulate and SOx control mechanism, at least in terms of today's proven technologies—to various other types of treatment (e.g., feed hydrotreating, ESPs, and SOx reducing catalysts).

Purely from the point of view of reducing air emissions of SOx, wet gas scrubbing is the best near-term *equipment-based* measure for FCCs. It can enable large SOx emission reductions, but carries a price tag. In addition, wet gas scrubbing often generates substantial volumes of waste water, bringing with it a considerable chemical oxygen demand (COD). In one sense, the problem of air emissions is mitigated, but the problem of water pollution can be increased by wet gas scrubbing; the adverse impacts need to be handled and mitigated. Likewise, the supply of fresh water to the scrubber may represent a challenge to the refinery.

Another methodology of major interest is increased hydrotreating of the FCC liquid feed. The feasibility of this measure is highly site-dependent. In very general terms, the ability of this measure to reduce SOx emissions is lower than it is for either wet or dry gas scrubbing. However, in some cases it is significantly more attractive from a cost effectiveness ratio point of view than any form of scrubbing.

Dry scrubbing the regenerator effluent gas stream is, in general, less efficient than at least one wet gas scrubbing technology in terms of SOx removal. Also, it is usually more costly. However, in certain circumstances, it was found to be somewhat competitive.

2. ETS RECOMMENDATION FOR FCCUs

Definition of Terms

The definition of Best Available Retrofit Control Technology (BARCT) appears in the April 3, 2008 Preliminary Draft Staff Report; namely, "…best available retrofit technology means an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

FCCUs

Based on an analysis of the results shown in Table EX 4.2, the recommended BARCT level for fluid catalytic cracking unit (FCCU) SOx emissions is 5 ppmv on a dry basis. This is derived from an achievable concentration when employing wet gas scrubbing (WGS), a proven technology demonstrated in practice on this type of emission source. It is believed that a lower outlet concentration is indeed possible. However, a lower concentration may not be reliably measurable because of unavoidable accumulated error in the source test reference methods and/or the permissible tolerance in continuous emission monitoring system (CEMS) measurements.

One WGS vendor, Belco Technologies Corporation (BELCO), has provided a lengthy application list **[1]**, with contracts awarded on as many as sixty-one (61) FCCU units and two (2) fluid cokers. Total FCCU capacity treated by BELCO scrubbers is noted as 3,228,700 bbl/day. The concept of using a WGS on an FCCU should be familiar to four (4) of the six (6) refining companies operating the Los Angeles, CA area since they are listed as customers employing BELCO WGS technology on the FCCUs at their other refineries.

BELCO has provided numerous wet gas scrubbers for FCCUs in the United States and on a worldwide basis. Based on that experience, BELCO has given a guarantee of 5 ppm SO_2 from a wet scrubber if installed on any of the FCCUs in the District. MECS DynaWave, with at least three installations on FCCU regenerator flue gas, will also guarantee 5 ppmv SO_2. BELCO has indicated that most of their units operate in the near zero ppm range, with the most recent performance test from one of these at a fraction of a ppm (corrected to 0% O_2). The study team is aware of another full-scale wet gas scrubber operating on an FCCU in a petroleum refinery at an SO_2 emission level of 5 ppmv or less on a long-term basis.

Another vendor of WGS technology, Exxon (Now ExxonMobil), has also developed WGS technology. It is used in their own refineries and at others under license **[2,3]**. As of 1999, they cite a total of fourteen (14) such installations. One of the Exxon papers **[3]** pictures a number of FCCU scrubbers located in tight spots because the required plot space was not otherwise available, including a photograph of a creative solution in which the scrubber is mounted on stilts above a road.

According to the District's Preliminary Draft Staff Report of April 3, 2008 based on EPA RACT/BACT/LAER Clearinghouse data, as well as another independent source **[4]**, the SOx limit currently being achieved or to be implemented shortly at various refineries in the U.S. by wet gas scrubbing is 25 ppmvd @ 0% O_2. This is equivalent to the limit contained in the recently enacted 40 CFR 60, Subpart Ja **[5]**. However, as explained above, one can do better.

BELCO has acquired a license from the BOC Group to supply NOx removal technology to the refining industry worldwide by means of ozone addition to their wet scrubbers. These scrubbers reduce SOx, particulate matter, and NOx in a single step. It is possible to pre-invest to incorporate the minor modifications necessary for ozone addition should the need for NOx removal arise in the future. Commercial demonstration of an ozone-equipped WGS began in February 2007 on the FCCU at a refinery in Texas **[6]**. Effluent NOx in the 10- to 20-ppm range and below is reported. Several other refinery clients are also listed under this technology in a second BELCO brochure **[7]**.

References

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3. Cunic, J.D. and E.M. Roundtree, "Control Technology Selection with MACT II FCC Particulate Emission Standards," Paper AM-99-17 presented at the 1999 NPRA Annual Meeting, San Antonio, TX (Mar. 21-23, 1999).

4. Leong, P.J., "ENGINEERING EVALUATION Tesoro Refining and Marketing Company PLANT NO. 14628 BANKING APPLICATION NO. 17798, Bay Area Air Quality Management District (BAAQMD), San Francisco, CA (Dec.15, 2008).

5. U.S. Environmental Protection Agency, "Standards of Performance for New Stationary Sources – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced after May 14, 2007," 40 CFR 60, Subpart Ja, U. S. Government Printing Office Electronic Code of Federal Regulations, Washington, DC (amended Dec 22, 2008, current as of Jan. 14, 2009).

6. Confuorto, N., "Report on Initial Operation of the World's First FCCU Application of the LOTOX Technology at a Texas Refinery," Paper ENV-07-100 presented at the 2007 NPRA Environmental Conference, Austin, TX (Sept. 24-25, 2007).

7. "DuPont® BELCO® Installation List ALL EDV® WET SCRUBBING SYSTEMS Including Boilers and Other Applications," 13-page Brochure," Belco Technologies Corporation, Parsippany, NJ (June 1, 2007).

3. SRU/TGTU SCRUBBING TECHNOLOGIES

Regenerative wet gas scrubbing was studied as a potential measure to reduce emissions from the SRU/TGTUs. Two manufacturers were considered for RWGS: BELCO's Labsorb and Cansolv. Cansolv was chosen, in particular for SRU/TGTU stack treatment, because they had more experience with SRU/TGTU incinerator stack gas scrubbing.

For treating effluent gas from the SRU/TGTU, the RWGS system is normally installed behind the tail gas incinerator to remove SO_2 that would otherwise be emitted to the atmosphere. The system consists of a pre-scrubber, an amine absorbing column, a regenerating column, and all of the associated pumps, heat exchangers, piping, and other associated equipment. In order to achieve substantial benefit from the Cansolv system, a number of the refineries included in this study may need to supplement the standard regenerative scrubbing package with additional processing. In some cases, a non-regenerative polishing step may be required as part of the Cansolv package.

Non-regenerative wet gas scrubbing of the sulfur plant tail gas was also studied (Tri-Mer's Cloud Chamber Technology). These units are typically less expensive to install than a regenerative system, but they consume large volumes of water and produce waste water. However, they are very effective at reducing SOx emissions.

4. ETS RECOMMENDATION FOR SRU/TGTU SCRUBBING TECHNOLOGIES

SRU / TGTU

Subpart J (Standards of Performance for Petroleum Refineries) in the New Source Performance Standards (NSPS) of 40 CFR 60 contains provisions for refinery sulfur plants. For a Claus sulfur recovery unit followed by incineration, the standard is 250 ppmv (dry) at 0 % O_2. For a system not followed by incineration and vented directly to the atmosphere, it is 10 ppmv of hydrogen sulfide (H_2S) and 300 ppmv (1.2 x 250) of reduced sulfur compounds, each calculated as ppmv of SO_2 (dry) at 0 % O_2. The term *reduced sulfur compounds* is defined as hydrogen sulfide (HS), carbonyl sulfide (COS), and carbon disulfide (CS_2).

Subpart Ja states the same limits for a sulfur recovery plant with a capacity greater than 20 long tons per day (LTD) of sulfur product. It adds that a sulfur recovery plant consisting of multiple trains or multiple release points shall comply with the same SO_2 limit for each process train or release point or as a flowrate-weighted average for all release points. Smaller sulfur recovery plants with capacity of 20 LTD or less are allowed to emit at 10 times the above limits. The term *reduced sulfur compounds* has the same meaning as in Subpart J.

Formulas are provided in Subpart Ja to calculate the allowable emission rate of SO_2 for Claus plants employing oxygen enrichment. These formulas reduce to the above limits when using 20.9 % O_2 (atmospheric air). In the extreme of 100 % O_2 fed to the Claus plant, they calculate to 800 ppmv and 8,000 ppmv SO_2 (dry), respectively, for large and small sulfur plants. The reduced sulfur compound limits at 100 % O_2 are 1.2 times the SO_2 limits; that is, 960 and 9,600 ppmv calculated as SO_2 (dry).

Except for one refinery, whose SRU tail gas is regularly vented, and another refinery whose combustion device is considered by the refinery <u>not</u> to be a treatment / control device of the tail gas unit, the 2005-baseline SOx in the SRU is about 100 ppmv (@ 0% O_2) or less. These figures are well below the 40 CFR 60 Subpart J (or Ja) standard of 250 ppmv SOx (@ 0% O_2).

Guaranteed outlet SOx concentrations of 5 ppmv after scrubbing can be achieved, in the worst case at 95% SOx removal efficiency; in most cases, the required scrubbing efficiency for a 5-ppmv SOx outlet is considerably less. BELCO has demonstrated experience in scrubbing the SOx from incinerated sulfur plant tail gas as well.

Except for the two aforementioned refineries, it has been found possible in this study also to reduce SRU ppm SOx to the atmosphere by the gas treating techniques investigated. Those results are all below 10 ppmv, and in many cases below 5 ppmv.

The ETS recommendations for SRU / TGTU emissions are therefore as follows:

- For uncombusted tail gas, the limits of Subpart J (Ja), namely 10 ppm H_2S and 300 ppm reduced sulfur species (total of H_2S, COS, and CS_2), should continue to apply. Refineries should be encouraged to reduce emissions so as to be able to vent rather than having to combust SRU / TGTU tail gas.

- For combusted / incinerated tail gas, 5 ppmv SOx @ 0% O_2 should be defined as the overall BARCT level for all refineries, based on scrubbed flue gas, but permissible to achieve by whatever means possible.

5. REFINERY BOILERS, HEATERS, FURNACES, ETC.

The boilers and heaters are the main places in a refinery where heat is generated to supply the different process units. They typically burn fuel gas, natural gas, LPG/butane, or mixtures of the aforementioned fuels. Sulfur species contained in their fuels (particularly fuel gas) are oxidized, producing SOx, which will either be emitted to the environment or removed from the effluent stream by treatment prior to emission. They collectively represent good candidates for "point source" emissions reductions, but, naturally, such treatment schemes only affect the gases discharging through the respective stacks. There are no "global" post-combustion devices.

In order to reduce emissions of SOx from heaters and boilers, two classes of measures were considered: pre-combustion, in which various sulfur species are removed from the incoming fuel, and post-combustion, in which SOx is removed from the combustion products. This module addresses the post-combustion treatment options for these pieces of equipment, whereas pre-combustion alternatives are discussed in the separate report for Module 2.

In particular, dry scrubbing and two forms of non-regenerative wet scrubbing (Tri-Mer's and BELCO's) have been considered as treatment technologies for boilers and heaters. While it is possible to consider the installation of a regenerative wet gas scrubber, this was not done for two main reasons:

1. The level of control that can be achieved by a pure regenerative system is generally lower than the level of control that can be achieved by a non-regenerative scrubber.

2. The cost of a regenerative system is substantially higher than the cost of a non-regenerative system. In circumstances where streams highly

concentrated in sulfur species are being treated, the revenue from sulfur sales and the reduced costs of reagents and disposal partially offset the initial capital costs. This offset can bring the annualized treatment costs for regenerative wet gas scrubbing in line with the costs for non-regenerative wet gas scrubbing. For boilers and heaters at the SCAQMD refineries, though, the effluent streams contain much less SOx than would be required to generate the necessary cash flow to offset the larger initial capital investment to a significant degree.

Wet gas scrubbing and dry gas scrubbing systems are both very effective at removing sulfur from combustion product streams. However, they are subject to economies of scale, as with most other processes in the chemical and petrochemical industries. Though the aggregated emissions from the top emitting heaters and boilers are roughly comparable to the SOx emissions from the FCCU or the SRU/TGTU, the individual emissions from any particular stack, are in many cases, lower by an order of magnitude. Because individual stacks are the mode of treatment for scrubbing systems, the costs per unit SOx removal may be higher for treatments applied to heaters and boilers than for treatments applied to the other units.

6. ETS RECOMMENDATION FOR REFINERY BOILERS, HEATERS, FURNACES, ETC.

For the heaters and boilers, post-combustion emission control is often very expensive due to the combination of the relatively low concentrations of SOx in flue gases and the division of the fuel gas stream among a number of heaters and boilers. Pre-combustion control, studied in Module 2, has been found to be more suitable for the majority of situations.

A 40-ppmv sulfur concentration in refinery fuel gas shows up as a SOx concentration of about 1/10 as much in the flue gas from combustion because of the nature of a hydrocarbon fuel and the combustion process. This amounts to about 5 ppm SOx. EPA acknowledges the equivalence of 162 ppm H_2S in fuel gas and 20 ppm SOx in the resulting flue gas (also 60 ppm H_2S and 8 ppm SOx) in the language of the subpart Ja for refinery fuel combustion. Within round off, those ratios (162:20 and 60:8) are the same as 40:5. Hence, a 5-ppm SOx concentration in the flue gas from refinery boilers and heaters is consistent with 40 ppm sulfur in refinery fuel gas.

Where wet scrubbing is involved, ETS recommends an overall BARCT value of 5 ppm SOx in the flue gas, consistent with both the guarantee level and an overall BARCT level of 40 ppm sulfur in refinery fuel gas. With present-day SOx measurement technology, there is no benefit in scrubbing when the resulting flue gas would contain SOx at less than the guarantee level.

IV. COST ANALYSIS

A. APPROACH & BASIS FOR COST ESTIMATE

A Discounted Cash Flow (DCF) cost analysis was performed for each selected application. The DCF approach determines the value of a project using the time value of money by estimating all future cash flows and discounting them to determine the equivalent present value cost. For consistency with other AQMD rule development projects and Air Quality Management Plan (AQMP), present value (or present worth value, PWV) was estimated with the following equation:

$$\mathbf{PWV = C + (CF_1 \times A) - (CF_1 \times S) + SUM\ (CF_{2,n} \times F_n)}$$

Where:

C = Capital cost, $, a single payment

A = Annual cost, $/yr, a series of uniform payments

S = Annual savings, $/yr, a series of uniform negative payments

F = Future cost, $, a single payment in a future year

CF_1 = Conversion factor from compound interest tables of the formula

$[(1 + i)^n - 1]/[i \times (1 + i)^n]$ where i = fractional interest rate and n = the nth year from the beginning. Used with a series of uniform payments from 1 to n.

$CF_{2,\,n}$ = Conversion factor from compound interest tables of the formula $1/(1 + i)^n$. Used with a single payment at any year n.

To be consistent with AQMD cost-effectiveness analysis, a 4% annual interest rate was used in the calculations.

The DCF includes all anticipated capital and expense costs (e.g., utility and infrastructure impacts) associated with the project or measure being evaluated. The capital portion of those costs includes materials, labor, and other directs, as well as engineering, management, taxes, shipping, and various indirect costs incurred for the particular control technology. (Note that the team attempted to estimate and include in the cost estimates all the monies required to construct and/or supply utilities (such as steam, electricity, and water), as well as infrastructure (e.g., sewer and wastewater treatment), associated with each measure.) Every cost item to be incorporated in the estimate is site and equipment specific. And, wherever possible, cost elements were individually listed, quantified, and costed via the use of applicable unit rates. In that fashion (i.e., “line-item” estimating, in lieu of purely factored costs), the relative precision of the overall estimate has been optimized. What’s more, reviewers of the cost development sheets will have the greatest insights into how the estimates were assembled; they will therefore be able to more easily adjust the results to reflect scope changes or improved data in the future.

Whenever possible, vendor/manufacturer budgetary quotes and local material/labor costs were used in our estimates. But when they were not available, AEC’s standard cost estimating methodologies for material and labor—all particular to refineries—were used to complete the pricing exercises.

B. APPROACH & BASIS FOR EQUIPMENT SIZING

The methodology and techniques utilized during this project in the sizing of equipment for a new application (e.g., for a sulfur treatment package) are exactly those used in any engineering endeavor. First, of course, we obtained a full understanding of how the existing system is configured and operates; those things are known by means of the site visit, underlying industry knowledge, interviews of refinery personnel, refinery-submitted data and drawings, etc. The second step was to conceptualize how the equipment under consideration is to be installed. This step also includes identifying the performance parameters to be achieved. In doing so, we quantified the expected ranges of service and efficiency, so that an appropriate over-design allowance could be applied (the purpose of which is to ensure that the performance objectives will reliably be met even if the underlying process is running at one extreme or another of its normal range). Next, all the pertinent information was communicated to the equipment representative, usually for pricing determination, but sometimes also to confirm the sizing exercise. In all cases, evaluating specific technology options required eventual coordination with the manufacturer or licensor to get verification of critical assumptions and/or conclusions.

Since the study encompassed multiple facilities and systems with widely different process flows and arrangements, and because, furthermore, there were several optional technologies looked at for each installation, the total collection of potential measures was extraordinarily large. Thus, it was impossible—in the timeframe available—to address every one of the individual cases with a full set of vendor inquiries. Instead, the team made use of generic, but representative budgetary quotations and published cost studies for the various technologies. Each such “reference point” (i.e., package cost and performance data for a prescribed process operating condition) was then used as a basis for extrapolation to other locations and design conditions. For a specific application, the key sizing criterion (typically the process throughput—e.g., SCFM of gas) is determined or calculated from the relevant operational data. Then, to generate the probable capital purchase cost ($PC), that criterion value (V) is divided by the comparable numerical capacity (Cr) from the “reference point” package. Using the baseline capital cost ($BCr) for that “reference point”, the desired capital cost is mathematically calculated via a conventional power curve relationship:

$$\$PC = \$BCr \times (V/Cr) \wedge n$$

where n is an appropriate exponent between .5 and 1.0

This approach is commonly used in engineering studies, and has been widely described in reference books such as Marks Standard Handbook for Mechanical Engineers and Perry’s Chemical Engineers’ Handbook. For our studies, the exponent value, n, was normally assigned a value between 0.6 and 0.7, a range that historically has given good estimates for industrial equipment packages.

Insofar as the pertinent sizing criteria were concerned, they were compared to nameplate duties for other, similar units for rough verification purposes. Also, input was sought directly from the manufacturers’ representatives, as well as public domain literature and published case studies. In the end, the checking procedures employed by the team members helped us to achieve rough, budgetary purchase costs, knowing that any loss in precision in arriving at those costs would be adequately covered by the very broad overall cost ranges (i.e., +/- 40%) expected for the ultimate results.

C. EQUIPMENT COST INFORMATION

AEC worked as closely as possible with the technology suppliers to gather the direct capital cost estimates for this project. (Where available, too, we compiled net installation costs which had been reported by the manufacturers for “reference points”, as described in the preceding section. Those “turn-key” costs were used to check the built-up cost estimates assembled by the project team.) Also, we took advantage of our relevant and extensive corporate knowledge base for similar projects. Every valid method was employed to give the best possible output. (In addition, as mentioned in Section A, above, indirect costs for impacts to utilities and infrastructure were estimated and included.)

The following list summarizes how the team typically pulled together a complete capital cost estimate for a given measure:

Cost category	Cost determination method(s)
Primary technology package	Obtain budgetary quote from vendor or use the aforementioned “power factor” equation for an extrapolated value. The study team tried to distinguish between where the Primary Technology Package is to be supplied as a skid type packaged units, loose as major components, or only as a process design and specification. Based on these different assumptions, hours for Engineering, Procurement, and Construction (EPC) contractors to design the balance of the package, procure remaining material, manage the project and construction, and construct the complete package have been included in the estimate. This cost also includes any equipment and material that is not part of the main vendor’s supply.
Discipline-specific commodities	Use approximate takeoffs and multiply them by historically confirmed unit rates, when possible; otherwise, employ suitable allowances. Approximate takeoffs have been developed by considering that material that might be supplied as part of a Primary Technology Package and that such portions of the materials might be designed, supplied and installed by an EPC contractor. Because of the preliminary nature of the layouts and designs, robust allowances for potentially greater material quantities in the final designs have been utilized when appropriate.
Construction labor	Use standard industry-specific unit labor rates for all the commodity items referred to above, and then compute the product of quantity times unit rate times basic refinery-specific hourly labor rate (the latter determined by laborer classification)
Indirect/overhead costs	Apply appropriate percentage factors against either sub-total labor or material costs

Engineering/management	Estimate specific manhour totals based on design experience in the industry and knowledge of the process and refinery-specific aspects of the measure
Project contingency	Choose an appropriate percentage to apply against the bottom-line capital cost estimate (the contingency used reflects the degree of uncertainty on the total package, and normally is between 25% and 40%, inclusive)

Owing to the fact that all the cost estimating tasks were conducted in a very preliminary, conceptual fashion, the overall accuracy of the capital cost determinations is no better than +/- 40%. Considerable engineering study would be required to refine the cost estimates and arrive at narrower accuracy ranges.

Besides specific technology and equipment provider quotations, we have incorporated the requirements that are specific to the technology, the refinery, and the geographical (plus geological) area. For all scrubbing technologies in this study we have added to the budget equipment quotations an allowance of fifty percent to accommodate seismic design (and permitting), metallurgy, and other technical issues. For wet scrubbing technologies, whenever the gas rate exceeded 80,000 SCFM, we have added equipment and costs for “plume mitigation”.

We are well aware of the multiple phases that projects of this magnitude go through, particularly in petrochemical plants and refineries, prior to receiving full funding and authorization to proceed into detailed design. Often a full front end engineering design (FEED) package is developed, which for many companies requires up to a 60% design effort and a ±20% cost estimate. But because of very real constraints on this project (such as time, budget, and minimum breadth of analysis), we did not have the luxury of developing a fully detailed engineering package for any SOx reducing measure. Instead, each estimate served as the best possible first pass amount for use in the DCF analysis mentioned above.

D. ANNUAL OPERATING COSTS

Unit rates for the principal cost-incurring utilities were requested from the refineries at the outset of the study. In several cases, explicit values were provided in response to the requests; those values were used as reported to us. For all other instances, generic estimates—obtained from other work by AEC at various U.S. refineries—of the unit rates were utilized. Of course, the explicit rate structures were refinery-specific, but the table below shows the ranges by commodity applied in the six individual reports:

Utility/Infrastructure	Unit of measure	Min. cost/unit	Max. cost/unit
Natural gas	MM BTU	$6.92	$10.13
Electricity	kw-hour	$0.05	$0.108
Fresh water	MM gallons	$2449	$4120
Wastewater treatment	MM gallons	$600	$6000
Cooling water	MM BTU	$0.50	$0.50
Compressed air	1000 scf	$0.15	$0.25
Solid waste disposal	ton	$100	$100
Sulfur*	Long ton	$35	$400

*--this commodity is a by-product of refining, and therefore provided revenue, not cost

The majority of the suggested control technologies or upgrades include the need not only for additional utilities but also raw materials, such as a scrubbing agent or catalyst. Costs for those items were estimated through consultation with a technology supplier or in-house expert. The appropriate third party resource or corporate engineer(s) based the quantity determinations on the specific characteristics of the technology under study. Once a quantity was determined, a local material cost was obtained for use in the calculations. Moreover, costs that recur at multiple-year intervals, rather than annually (e.g., those incurred during turnarounds or periodic major maintenance activities), have been accommodated in the project's workbooks.

Early in the project, AEC had requested from the refineries the average hourly costs for various labor classifications on typical capital projects. When plant-specific values were not provided, we used generic labor rates that are intended to reflect average fully-burdened costs for jobs inside a South Coast refinery. The value ranges are shown below:

Labor Classification	Lowest hourly labor rate	Maximum hourly labor rate
Laborer	$90	$106
Civil/Concrete Worker	$90	$106
Structural/Iron Worker	$95	$113
Painter	$90	$106
Insulator	$100	$106
Mechanical/Machinist	$105	$108
Boilermaker	$106	$115
Pipefitter	$95	$109
Electrical/Electrician	$106	$113
Instrumentation Tech	$106	$113

The computation of chemical (such as NaOH) quantities used by the various measures, and the amounts of waste products generated by them, were very straightforward. In almost all instances, the manufacturers' literature provided guidelines and/or explicit case studies. That information was used via direct "scale-up" multipliers, based on the key parameter(s) involved—such as total elemental sulfur removed. When no definitive data was available, stoichiometric calculations were performed and suitable allowances made for incomplete reactions, design overfeed percentages, etc.

When it came to estimating the engineering and construction management manhours required to design and implement a given measure, the AEC team used its experience gained from performing similar projects. Also, actual records from various refineries for executed projects of similar types were consulted. In the end, the manhour quantities were reviewed for reasonableness, all in light of the very extensive requirements imposed by the six refiners for completeness and documentation of capital projects.

The worksheets into which all the aforementioned information has been entered make automatic calculations of annual operating costs. They permit the easy adjustment of parameters, such as utility rates and labor demands, in case updated values are later made available. The final programmed calculation is the one that finds the PWV (Present Worth Value) of each measure's multi-year cash-flow. That value is computed using the same 4% discount factor mentioned above. It represents, in 2008 dollars, the single lump-sum expenditure that is equivalent—in financial terms—to the said cash-flow distribution.

Annual usage of solvents and utility (e.g. natural gas, electricity) usages are summarized in the confidential appendix of each refinery for the specific measures selected for emission reductions.

E. COST EFFECTIVENESS ANALYSIS

The cost effectiveness, **CE** ($/ton SOx reduced), of a prospective technology installation for this study is defined as the ratio:

$$\mathbf{CE = PWV / (25 \times SR)}$$

where **PWV** is the *Present Worth Value* (units: $),
SR is the *annualized reduction in SOx emissions* (units: tons), and
25 is the economic life (in years) of the measure

In computing for a particular measure (at a specific refinery) the expected annual reduction in SOx emissions (the term "SR", above), the AEC team first determined the baseline emissions for the equipment or system. Those emission amounts are the ones that the refinery either measured or calculated, and then reported to the AQMD, all in accordance with the accepted protocols for major source reporting. When data from that year was available, the baseline amount was for the full 2005 fiscal year; otherwise, the quantity as reported from the next or a subsequent year was selected.

Next, the candidate technology or approach was evaluated in light of the equipment's or system's operating characteristics. This was done to arrive at either (a) a directly computed net mass for the expected annual SOx reduction, (b) the expected percentage reduction in SOx emissions, by implementing the measure, or (c) by the expected concentration of SOx in the effluent stream. For scrubbing applications studied here, the concentration of SOx in the effluent stream typically governed the savings calculation. In other words, for most scrubbing measures studied, there is not enough SOx in the proposed inlet stream to allow for the removal of SOx at the reported percentage levels. Instead, the SOx concentration was reduced to a critical level, beyond which further reduction is not assured. The outcome is then reported as a predicted reduction, in tons/year, of total SOx emissions; that is the parameter "SR". (The theoretical SOx emissions reduction percentages, in general, are always in agreement with published data and/or marketing/sales data for the respective technology or system.)

In a parallel effort, and as defined in a previous section, the "PWV" for the measure was computed. Certain underlying assumptions were utilized in that calculation. Those primary assumptions are shown in Table 4.1 below:

Table 4.1 List of Assumptions for Cost Analysis

The following list provides assumptions/information used in the cost analyses for refinery controls. These assumptions are generalized to cover the several types of controls and process equipment analyzed. Many of the following assumptions need to be refined once more detailed study, under separate contracts, of selected measures is undertaken.

- Costing is for scrubbers of one type or another at each site and for each process to be controlled. Scrubber equipment cost is based on one or more quotes or cost studies for known sizes of each type of scrubber. AEC estimated major equipment costs for each of the refinery processes to be analyzed by using "the six tenths power factor" rule applied to vendor information as described in Section IV B of this report.
- Especially for large projects, significant front-end engineering design (FEED) and project management costs are incurred (thousand or tens of thousands of hours for FEED and thousands of hours for management) It should be noted that the

number of engineering hours chosen for arriving at the project costs is an assumption. These hours are based upon AEC's first-hand experience as well as reported refinery experience.[1]

- For all projects, representative contingency allowances, based on the nature of the project, have been made.[2]
- For all projects, a fixed design development allowance of 10% has been stipulated.[2]
- The baseline emissions for each plant's processes are supplied by SCAQMD or the refineries.
- Scrubber control efficiencies are based on vendor estimates for similar processes.
- Life of control equipment is 25 years after startup in all cases.
- An annual discount rate of 4 percent is used and all costs are in 2008 dollars.
- Purchased equipment costs for the scrubbers are estimated with auxiliaries, instruments, freight, and taxes.
- Costs include site preparation and construction based on the footprint of the control equipment. (It should be noted that when installing equipment in an existing refinery, the vendor's proposed footprint may not be accurate as the equipment may need to be separated to fit in the existing area and some equipment may be located off-site for space or operating considerations. Therefore "robust" material take off allowances are justified to deal with this spread out footprint.)
- Installation costs include labor and materials.
- Added charges for seismic considerations (Zone 4) are included in equipment costs.
- Added charges for waste or wastewater treatment equipment are included in equipment costs unless treatment is performed outside of the boundary limits for the control measure. In these cases, the treatment costs have been calculated according to the treatment requirements and site-specific unit costs provided by the refineries.
- Annual operating/maintenance costs are estimated from equipment and labor costs at rates obtained from the refineries or from rates for similar workers at other refineries. The fully burdened rates are from \$90 to \$113 per hour and are listed by labor classification in Section IV D of this report.
- Overhaul (turnaround) maintenance is performed every 5 years starting the fifth year after startup
- Startup may be 1 to 3 years after the project begins, but all capital cost for the equipment and installation is spent in the first year. Capital required for installation is expected to be larger in years after the first and is apportioned likewise. (There are, however, exceptions to the preceding. The details depend on the length of delivery and schedule of construction. Some equipment might have a delivery of one year or more and construction cost will not occur until the unit is delivered and installed, which will be beyond one year. Cost might be "committed" in the year but not "expended" until the invoices are actually paid, so the timing of costs becomes a project-specific question. Also, note that a major project start-up might not be until 5 years after the project is initiated in Front-End development.)

- Utility rates in $/unit during construction and operation are as reported by the refineries under study, or if not available, from similar refineries elsewhere. Ranges of costs for the various utilities are given in Section IV D of this report.
- Accuracy of the costing is estimated by AEC at no better than +/- 40 percent and of the subsequent cost effectiveness at –10 to +50 percent.

Footnotes:

1) Estimated Engineering Hours:

ETS decided to test the AEC assumption by contacting three parties with significant experience in estimating and implementing the installation of air pollution systems, in particular SOx scrubbers. All three were asked to estimate the number of engineering hours required to specify, design and install a 100,000 to 200,000 ACFM wet scrubber system for SOx removal at a California refinery.

The first of these estimates was obtained from an executive of a relatively small firm that provides turnkey systems. This executive has a wealth of hands-on experience in the design and supply of air pollution control projects. His estimate of 6,000 to 9,000 engineering hours was based on a recently completed contract. Included in his estimate was an adjustment (increase in hours) to accommodate anticipated demands and complexity of a refinery project.

The second estimate was from a well-respected engineering manager at a relatively large Midwest engineering firm. His estimate was between 20,000 and 30,000 engineering hours.

The third estimate was a utility firm project manager who had recently completed a retrofit of a very large multi-unit and baghouse system for control of coal-fired boiler SOx and particulate emissions. He stated that "if the engineering scope includes foundations, electric power, ductwork connections, access, elevators, fly ash system, flow modeling, P&ID's, etc, he would think the work could require at least 10,000 man hours (5 man-years), and quite possibly closer to the 30,000 man-hour estimate".

Based on the above ETS believes that the engineering hours used in the cost estimations in this report are conservative and given the softening in the economy it is possible that the actual hours could come in below those used here.

It should also be noted that engineering hours are separated into two categories, front-end engineering and design (FEED) hours, and a design allowance taken as a percentage of total materials, labor, and overheads required to complete a project. This latter percentage is not part of, for example, the 30,000-hour estimate given above.

2) Contingencies:

In Module 3A ETS/AEC has assigned 10% for design allowance and 35%-40% for contingency. The contingency used for measures M12 and M13 was 35%. All others measures addressed in this Module were assigned a contingency of 40%. It should be noted that the EPA Air Pollution Control Cost Manual, 6th edition, lists contingency percentages for most of its control systems as 3% of purchased equipment cost (PEC). PEC consists of equipment and auxiliaries, instrumentation, sales taxes, and shipping.

The spreadsheets for estimating PWV are adapted from a procedure that estimates net present value on a line-by-line (year–by-year) basis beginning a specified number of years before startup (1 to 4). Capital costs for equipment purchase and construction are included in the years preceding startup. This procedure estimates net present values that are different from AQMD's PWV.

Because of this difference the spreadsheets have modifications that use the line-item costs, but regroup them in a manner suitable for use in the PWV equation.

- Categorized costs include:
  - Demolition and decommissioning
  - Civil/concrete
  - Structure
  - Equipment
  - Piping and Mechanical
  - Electrical and controls
- Miscellaneous line items include:
  - Contractor overhead, typically 8 % of direct field labor (DFL)
  - Contractor field supervision, typically 12 % of DFL
  - Mobilization/demobilization, typically 10 % of DFL
  - Overtime/productivity factor, typically 12 % of DFL
  - Freight and shipping, typically 8 %, of materials
  - Sales tax, typically 7 % of materials
  - Commissioning and operating spares, typically 5 % of materials
  - Startup/initial fill material, typically 2 % of materials
  - On-site training/startup assistance, depends on project
  - Front-end engineering design, depends on project size
  - Project management, depends on project size
  - Design development allowance, 10% of total
  - Contingency, 25-40% applied against the bottom-line capital cost estimate

GENERAL COST EFFECTIVENESS RESULTS

In general, the costs for emission reductions due to measures in Module 3A are significantly higher than the measures studied in Module 2. The costs per ton of SOx emission reduction are extremely high when the opportunity for reductions in emissions is lowest. As the opportunity for reduction increases, the costs become, on average, not as high.

The most effective measures in Module 3A show a capacity for SOx emission reductions that can be more than double the most effective measures in Module 2. Some of the measures in Module 3A show a potential to reduce SOx emissions by more than 300 tons per year. However, most of the measures show a much smaller potential for reductions in SOx emissions.

Almost all of the SOx reducing measures studied in this module are predicted to cost in excess of $20,000 per ton. Of well over 100 implementations studied, only 6 are predicted to reduce SOx emissions at a cost of less than $20,000 per ton. All of those exceptions are more costly than $10,000 per ton of reduction.

Non-regenerative wet gas scrubbing is typically less costly and more effective than either dry scrubbing or regenerative wet gas scrubbing according to the preliminary analysis in this work. The low SOx concentrations in the feed streams and strict control targets make NWGS particularly suitable. Other scrubbing technologies are, however, expected to be quite capable of reducing SOx emissions from these refineries and should not be automatically discounted. Detailed analysis of the most attractive measures may result in refinement of the results in this study. In some situations RWS or DS may be ultimately favorable.

The cost effectiveness of SOx reducing measures tends to be most favorable for the largest single source emitters. Typically, measures for reducing SOx at the FCCU and SRU/TGTU are favored among Module 3 measures. Scrubbing measures applied to heater and boiler systems are typically less cost effective than those applied to larger emitters.

The average cost for scrubbing at the FCCU stack, using the measures recommended, is expected to be about $25,000 per ton of captured SOx. For scrubbing at the TGTU, the average cost (again taking into consideration the designated Module 3A measures) has been estimated as about $47,000 per ton. For refinery heaters and boilers, the overall average cost (there being none recommended by the study team) is over $250,000 per ton. The most cost effective application in refinery heaters and boilers has a cost effectiveness of $68,000 per ton, higher than the Module 3A averages in either the FCCU or TGTU area.

COST EFFECTIVENESS FOR FCCU MEASURES

The cost effectiveness for using scrubbing technologies for emission control ranges between about $13k per ton and about $190k per ton. The control capability varies from about 27 to almost 350 tons/year. Of the technologies studied here, BELCO's non-regenerative wet gas scrubber has the greatest capability to reduce SOx emissions in general and typically has a lower cost per ton for emissions reduction than its competitors. Its cost effectiveness falls in a range between $12,800 and $76,000 per ton. The removal capabilities fall between 70 TPY and almost 350 TPY. Other scrubbers evaluated are typically more costly, on a per ton basis and less effective for treating flue gases from FCC regenerators.

All of the scrubbing technologies have very good SOx removal capabilities and are expected to reduce the SOx concentration in the flue gases from the FCCU regenerator to as low as 5 ppmv. The wet gas scrubbers tend to be slightly more effective and cost efficient than the dry gas scrubbers. However, the most suitable technology will be dependent on the specific cases. For some refiners, a dry scrubber may be preferable.

COST EFFECTIVENESS FOR SRU/TGTU MEASURES

Based on the cases examined in this study, the capability of the scrubbing technologies to control SOx emissions from the SRU/TGTU in the SCAQMD area refineries ranges between 14 and 106 tons per year. The cost effectiveness ranges between approximately $36,000 per ton and $154,000 per ton. One studied measure had a SOx reduction cost effectiveness ratio of over $26 MM per ton. This measure has been omitted from the above ranges because due to a low SOx reduction capacity, it is not particularly illustrative of emission reduction opportunities.

The costs of installing and operating non-regenerative wet gas scrubbers have been found to be lower than the costs of installing and operating a regenerative wet gas scrubber, particularly when the SOx removal is at the low end of the scale. In those situations, the cost effectiveness ratio ($/ton removed) of the NWGS is significantly lower than that of comparable RWGS applications. Furthermore, the SOx reduction capabilities of NWGS are expected to be superior to those of RWGS in the applications discussed here.

COST EFFECTIVENESS FOR BOILERS/HEATERS/FURNACES MEASURES

Of the 93 cases for emission control at boilers, heaters, and furnaces, 71 are expected to have reduction capabilities of less than 10 tons per year. Of those, the one with the *best* cost efficiency has a cost effectiveness ratio of roughly $200,000 per ton. Therefore, these measures are expected to be particularly ineffective.

With respect to the remaining 22 measures, SOx reduction capabilities range from 11 tons per year to almost 40 tons per year. The costs associated with these measures are still large, from $68,000 per ton to $276,000 per ton. The most efficient scrubber for boilers, heaters, and furnaces is a wet gas scrubber that is predicted to reduce SOx emissions by 40 tons per year at a cost effectiveness of nearly $160,000 per ton.

While non-regenerative wet gas scrubbing tends to be superior to other measures in this section, it is generally very costly to implement and less effective at reducing SOx emissions than many of the other measures studied in Module 3A and other Modules in this study. In particular, pre-combustion treatment (Module 2) has been shown to be a more effective means of reducing emissions from the very same heaters and boilers than post combustion treatment. Other measures, too, across the FCCU, SRU/TGTU, and fuel gas systems are more cost efficient and effective than scrubbers for individual heaters and boilers (or small groups of them).

COST EFFECTIVENESS FOR RECOMMENDED MEASURES

Based on the designations made by the study team, the following table gives a summary of the cost effectiveness ratios by refinery following implementation of the respective measures in Module 3A:

Table 4.2

Module 3A Cost Effectiveness ($/ton of SOx) by Refinery

Refinery:	1	2	3	4	5	6	**Avg. for All**
Equipment Type							
FCCU	$14.4k	$76.2k	$36.6k	$42.1k	$11.6k	$12.8k	**$24.6k**
SRU/TGTU	N/A	$39.0k	N/A	N/A	$123.2k	$36.4k	**$46.8k**
Htrs/Blrs/etc.	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
All Above Types:	$14.4k	$58.8k	$36.6	$42.1	$123.2k	$18.4k	**$28.8k**

Note: The entry "N/A" above means one of the following three things for the relevant refinery and equipment type combination: (a) for technical reasons, a Module 3A measure was not practical; (b) the cost effectiveness of candidate measures were too high for designation; or (c) a Module 2 measure (see the separate report) was determined to be the best technology for the equipment type at that site

F. TOP-DOWN APPROACH

Selection Process for Recommended Emission Reduction Measures

For the refinery operations discussed in this report the following sections show how emission reductions were estimated and how recommended treatment measures were selected. Initial operations and emission points for study were chosen from questionnaire responses and visits to the refineries. These choices were then analyzed and compared from data supplied by the individual refineries and from equipment vendors. Spreadsheet models were used to develop SO_2 quantities before and after control equipment, then to estimate costs of control and cost effectiveness. The top-down approach followed here consists of identifying sources expected to be the higher emitters, then analyzing performance and cost, first of the expected most effective control systems, then the second most effective system.

FCCUs and Boilers/Heaters

During the selection process for FCCUs and Boilers/Heaters, questions arose as to the appropriate measurement for establishing control effectiveness: efficiency (98 or 99 percent) or outlet concentration (5 ppmv). As discussed above, 5 ppmv SO_2 at a control outlet may be a lower limit because of measurement capabilities. If using efficiency, the control device effectiveness varies for different designs and conditions. For this work the BELCO wet scrubber is assumed to be capable of 98 percent efficiency and the Tri-Mer Cloud Chamber wet scrubber of 99 percent efficiency. Both values are vendor information, but may be conditioned on inlet concentration, temperature, and other factors.

To accommodate both measures of effectiveness, parallel calculations of scrubber efficiency and outlet SO_2 concentration are used in the emissions reduction portion of the costing spreadsheet models. If the scrubber's efficiency would indicate an outlet concentration lower than 5 ppmv, the scrubber is assumed to operate at the efficiency equivalent to 5 ppmv for purposes of estimating SO_2 reduction and cost effectiveness. This procedure is applied to scrubbers for FCCUs, Boilers/Heaters and some SRU/TGTUs. The results of the emission reductions and cost effectiveness estimates based on the lowest efficiency levels (98 or 99 percent efficiency) are shown in Appendix A, Table A-3 and Table A-4, respectively.

SRU/TGTU

Several measures were examined for effectiveness across the refineries. To answer questions about how measures were selected for SRU/TGTUs, tables were constructed to show the measures identified as possible fits for each refinery and are shown in the confidential appendices. Reductions in SO_2 and estimated cost effectiveness were inserted for each refinery, with the measure selected printed in bold type.

In three cases the recommended emission reduction measures have the combination of lowest cost and greatest quantity of SO_2 removed. In the remaining three cases the measures are chosen as the apparent best combination of high SO_2 removal and low cost.

G. RECAP OF DATA REQUESTS

Many technical data requests were issued to all of the refineries (and the AQMD) during the course of this study. The vast majority of them were made prior to the initial site visits by means of a comprehensive questionnaire. Each refinery responded to the questionnaire by furnishing tabulated data and reference drawings/documents. Likewise, they responded to the handful of post-visit requests with appropriate follow-ups. Specific details of the information requested and received can be found in the confidential appendices for each refinery.

H. EQUIPMENT SPACE REQUIREMENTS

Wet gas scrubber equipment footprints and space requirements for the FCCUs and the SRU/TGTUs are shown in the confidential appendices for each refinery where measures have been selected. These specifications have been compared with the plot plans provided by the respective refineries, and where applicable, are presented in the costing workbooks.

I. CONCURRENT EFFECTS ON OTHER AIR POLLUTANTS

The recommended technologies should have an effect on mass particulate and fine particulate emissions. Fine particulate impact will be lessened by reducing SO_2 emissions which is a $PM_{2.5}$ precursor. The technologies are expected to have minimal impact on NOx, ammonia, and volatile organic compound emissions.

J. MULTIMEDIA IMPACTS

The following multimedia impacts of wet gas scrubbing of FCCU regenerator flue gas were considered.

- Water usage
- Wastewater treatment of scrubber effluent
- Wastewater disposal
- Disposal of captured catalyst solids
- Permitting of wastewater discharge and disposal of captured catalyst solids
- Mitigation of scrubber steam plume

Some refineries may be limited in the amount of additional water available for their use. To mitigate water usage, the scrubbing water is re-circulated, with a bleed stream to wastewater disposal. Makeup water is added to replace this blowdown plus the water evaporated into the scrubbed gas stream. Costs to obtain additional water either from an external source or by reallocating the water already used in a given refinery are one of the items covered in the contingency.

A self-contained wastewater treatment system to oxidize the sulfite / bisulfite content of the scrubbing solution and to separate catalyst solids from the slurry purged from the scrubber is included in the scrubber cost, as are the addition of caustic soda and the pH control system for the re-circulated scrubbing water.

The clarified wastewater is to be discharged with other refinery wastewaters. If an additional sewer allowance for increased flow must be purchased, NPDES limits increased, or wastewater discharges cut in other areas of the refinery, those costs are included in the contingency as well.

Captured catalyst solids are separated in the integral wastewater treatment process included in the cost of the scrubber. These solids are typically recycled for reuse by a cement company either in solid form as practiced in the disposition of dry solids removed in an electrostatic precipitator or wet solids from scrubbing. The water content of the concentrated slurry is said to be desirable for the cement company. Costs for removal and disposal of catalyst solids are included in the estimate.

The wet catalyst solids captured by the FCCU flue gas scrubber at one refinery and the dry catalyst solids removed by electrostatic precipitators from the FCCU flue gas at two others are recycled to a cement company or companies for beneficial reuse. As such, this material is not considered a waste, much less a hazardous waste.

Permitting of wastewater discharge is not considered a problem, provided that it is properly treated and this additional volume can be tolerated within the refinery's discharge limits. Recycling of the catalyst solids to a cement company constitutes reuse and does not trigger solid / hazardous waste permitting and disposal. Recycling does not single out the solids for special treatment in a special category or special landfill since they are not regulated as a waste when recycled for a beneficial use.

The aesthetic problem of a visible steam plume is especially of concern at locations easily visible from adjacent freeways and residential areas. In those cases where the net gas discharge rate is high (i.e., over 80,000 SCFM) and the potential exists for a major steam plume, then plume mitigation is planned and costs are allocated for it. For the purposes of this study, the method to be used is cooling (via air-cooled heat exchangers) of the recirculating liquid pumped from the scrubber and ultimately back to it. That will dramatically reduce the magnitude of the plume, and has been shown to be effective in other installations.

Additionally, the so-called “problem” can be neutralized by a proactive public relations effort before the fact. One refinery conducted an extensive public outreach campaign to mitigate negative public perception about the steam plume resulting from their new wet gas scrubber. This included color brochures related to the wet scrubber; its plume; and environmental, health, and safety matters for public dissemination plus a huge sign hung in the refinery. Since the scrubber began operation, the refinery has not received any public complaints related to the steam plume.

APPENDIX A – DATA TABLES

Table A-1

Summary of Baseline Emissions, Emission Reductions, and Theoretical Remaining Emissions for Implementing Selected Measures in Module 2 and Module 3A

Part (a) – SOx as of 2005 [tons per day (tpd)]

Refinery Number / Process:	1	2	3	4	5	6	Total
FCCU	0.61	0.31	0.36	0.25	0.96	1.04	3.52
SRU & Tailgas	0.16	0.20	0.30	0.05	0.09	0.31	1.11
Others[1] (by difference)	0.09	0.40	0.34	0.70	0.83	0.51	2.87
Total	0.86	0.91	0.99	1.00	1.88	1.86	7.50

Part (b) – Projected SOx Reductions [tons per day (tpd)]

Refinery Number / Process:	1	2	3	4	5	6	Total
FCCU	0.58	0.19	0.28	0.20	0.87	0.94	3.07
SRU & Tailgas	0.13	0.17	0.15	0.04	0.06	0.29	0.83
Others[2]	0.06	0.07	0.03	0.35	0.33	0.04	0.89
Total	0.77	0.43	0.46	0.59	1.26	1.27	4.78

Part (c) – Theoretical[3] Resulting SOx [tons per day (tpd)]

Refinery Number / Process:	1	2	3	4	5	6	Total
FCCU	0.03	0.12	0.08	0.04	0.09	0.10	0.45
SRU & Tailgas	0.03	0.03	0.15	0.01	0.04	0.02	0.28
Others[2]	0.02	0.33	0.30	0.36	0.49	0.47	1.98
Total[4]	0.09	0.48	0.53	0.41	0.62	0.59	2.72

Notes:

1. This includes boilers, heaters, furnaces, cogen plants, and other combustion units firing refinery fuel gas.
2. As in Note 1 above and enumerated in Matrix Table.
3. The measures in Modules 2 and 3A are not independent of one another, thus care was taken when arriving at the facility total.
4. Entries in the Part (c) table are the difference between Part (a) and Part (b) numbers.

TABLE A-2
Summary of Selected Measures, Emission Reductions and Average Cost Effectiveness

	REFINERY 1		REFINERY 2		REFINERY 3		REFINERY 4		REFINERY 5		REFINERY 6		TOTAL EMISSION REDUCTION	
	Reduction (TPY)	CE ($/ton SOx)	Reduction (TPY)	CE ($/ton SOx)	Reduction (TPY)	CE ($/ton SOx)	Reduction (TPY)	CE ($/ton SOx)	Reduction (TPY)	CE ($/ton SOx)	Reduction (TPY)	CE ($/ton SOx)	TPY	TPD
FCCU MEASURES													**1,119.42**	**3.07**
M1	211.82	$14,437	69.76	$76,211	103.56	$36,636	74.54	$42,103	317.60	$11,600	342.14	$12,849		
SRU/TGTU MEASURES													**301.91**	**0.83**
M13	46.78	$22,410			53.00	$12,881	13.69	$54,686						
M16														
M17			61.38	$39,000					20.75	$123,186	106.31	$36,359		
FUEL GAS SYSTEM MEASURES													**323.39**	**0.89**
M20							126.70	$4,903			14.50	$57,428		
M20B					12.84	$46,905								
M20A									14.74	$31,035				
M21B									106.20	$19,688				
M21A			25.22	$30,948										
M22	23.19	$2,395												
HEATERS/BOILERS													**N/A**	**N/A**
None Selected														
TOTAL EMISSION REDUCTION (TPY)	281.79		156.36		169.40		214.93		459.29		462.95		1,744.72	
TOTAL EMISSION REDUCTION (TPD)	0.77		0.43		0.46		0.59		1.26		1.27		**4.78**	
COST EFFECTIVENESS ESTIMATION													**Average CE for 6 Refineries**	
Average Cost Effectiveness ($/ton SOx Reduced)	$14,770		$54,303		$29,982		$20,975		$36,025		$19,644		**$25,533**	

TABLE A-3

Module 3A Forecasted SOx Reductions(tons/day) by Refinery at Theoretical Efficiencies

Refinery:	1	2	3	4	5	6	**Total**
Equipment Type							
FCCU	0.60	0.30	0.35	0.24	0.94	1.01	**3.45**
SRU/TGTU	N/A	0.20	N/A	N/A	0.07	0.31	**0.58**
Htrs/Blrs/etc.	N/A	N/A	N/A	N/A	N/A	N/A	**0.00**
All Above Types:	0.60	0.50	0.35	0.24	1.01	1.32	**4.04**

Note: The entry "N/A" above means one of the following three things for the relevant refinery and equipment type combination: (a) for technical reasons, a Module 3A measure was not practical or (b) the cost effectiveness of candidate measures were too high for designation; or (c) a Module 2 measure (see the separate report) was determined to be the best technology for the equipment type at that site.

TABLE A-4

Module 3A Cost Effectiveness ($/ton of SOx) by Refinery at Theoretical Efficiencies

Refinery:	1	2	3	4	5	6	**Avg. for All**
Equipment Type							
FCCU	$14.0k	$48.0k	$29.5k	$35.2k	$10.7k	$11.9k	**$21.5k**
SRU/TGTU	N/A	$32.9k	N/A	N/A	$95.8k	$34.3k	**$41.5k**
Htrs/Blrs/etc.	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
All Above Types:	$14.0k	$42.1k	$29.5k	$35.2k	$95.8k	$17.1k	**$25.2k**

Note: The entry "N/A" above means one of the following three things for the relevant refinery and equipment type combination: (a) for technical reasons, a Module 3A measure was not practical or (b) the cost effectiveness of candidate measures were too high for designation; or (c) a Module 2 measure (see the separate report) was determined to be the best technology for the equipment type at that site.